**2024 ACC Draft Calculator Workshop 2024-07-23-13-04-12**

0:00  
Next, just regarding the recording is in progress.

0:03  
Perfect.

0:04  
So regarding the agenda and schedule, first we will have an opening by the Commissioner as we walk through this workshop agenda which we're doing now.

0:11  
Funny enough, afterwards will be the comparison of 2024 and the 2022 ACC, also the TRC results and the discussion slash Q&A afterwards.

0:23  
Following that, we'll go to the overview of the SERVM data following and then the discussion Q&A after that.

0:30  
Next will be a discussion.

0:31  
We'll go into the integrated calculation of generation capacity and GHG avoided cost and then have the discussion in Q&A afterwards.

0:40  
Following that, we will take a 10 minute break.

0:43  
After the 10 minute break, we will go into the allocation of generation capacity value to EUE hours with the discussion Q&A following that.

0:51  
Then we will go into transmission distribution, avoided cost and then we'll talk about have a discussion Q&A after that.

0:57  
Then lastly, we will go over to societal cost test methodology and results and have a discussion Q&A after that.

1:04  
So to kick things off though, we're going to have our opening remarks by Commissioner Houck.

1:09  
So let's take it away.

1:10  
Commissioner Houck.

1:12  
So thank you.

1:15  
I want to thank Energy Commission, Energy Division staff for all of the work in putting today's workshop together.

1:22  
Thank you, Alex for facilitating today's workshop.

1:26  
And just good afternoon to everyone that is listening in.

1:31  
I want to also thank E3 and Astrup to review for their review of the ACC update and the results of the 2024 draft ACC that that was recently released.

1:44  
So the ACC as most of you know is used to determine the avoided cost caused by reductions to electrify to electricity and gas consumption as well as determining the benefits of customer programs that promote Ders like energy efficiency and demand response.

2:01  
And that the ACC is updated every two years.

2:04  
We recently issued a proposed decision that proposes changes to the ACC to better align with the modeling of the calculator with the most recent updates of the IRP proceeding.

2:16  
And these updates will better enable the Commission to evaluate the cost effectiveness of demand side DER resources alongside supply side DER resources.

2:25  
And we are going to be discussing all of these things today.

2:28  
I'm looking forward to the discussion and again want to thank E3 Astrape and our Energy Division staff for all of the work in putting today's workshop together and for all of the parties and participants in today's workshop look forward to the discussion and the questions.

2:46  
And with that, again, I want to keep my comments brief so we can get to the part of the discussion today and we'll turn it back over to Alex.

2:56  
Thank you, Commissioner Houck.

2:57  
And with that, I'll pass it over to E3 to let's talk about the comparisons of 2024 and 2022 to receive what it costs and do ask state next slide so I know when to switch over.

3:11  
Thank you.

3:12  
Great.

3:13  
Thank you, Alexa.

3:14  
Thank you, Commissioner.

3:15  
Just say sound test.

3:16  
Can people hear me?

3:18  
OK?

3:20  
Perfect.

3:21  
All right, My name is Fangxing Liu

3:24  
I'm a senior consultant here at E3.

3:27  
I've been supporting the CPUCACC for the past few years.

3:30  
So very excited to be here and then share the newest results for 2024 ACC.

3:36  
All right.

3:37  
Let's move on to the next slide.

3:42  
Before we dive into the results and the comparison, I first want to use this slide as a level set for the discussion we're about to have.

3:53  
This hopefully will be a reminder for most of the folks, but I think it's still important to go over this slide as a reminder of the principles for the What A cause framework and this would also apply for the ACC in general.

4:11  
So the first principle of the ACC is that it is marginal.

4:17  
The avoided cost we're calculating here, it represents the cost that utility could avoid by installing a marginal unit of the ER relative to existing or planned portfolio.

4:29  
Together, this cost should serve as implicit and explicit implicit and explicit price signals to achieve California's long term goals like energy reliability and GHG reduction.

4:42  
And the second principle of the avoided cost framework is that it should represent a long term value.

4:49  
So we're calculating the long run avoided cost of ADR over its lifetime.

4:55  
In this case it will be 30 years for each ACC cycle.

4:59  
And then also these avoided costs should really be aligned with the long term planning expectation for meeting California's long term goals.

5:08  
And finally, hopefully we all know that what IT cost is a technology agnostic tool.

5:14  
It is a single flexible hourly streams that is used to evaluate a variety of DERs, including low reducing, low shifting and low increasing.

5:25  
All right, so with that we'll dive into the 2024 ACC.

5:33  
This is a very text heavy slide, but I want to put it out there so that we are all on the same page on what we've changed for the 2024 ACC.

5:44  
Want to start from top to bottom and the key changes are highlighted in orange or red.

5:51  
OK.

5:52  
So the first void describes the major changes for the 2024 ACC in terms of methodology that was proposed and adopted in the recent proposed decision.

6:04  
First is that starting in this cycle, we'll be using the IR PSP latest adopted system plan, that is the 2023 preferred system plan PSP rather than the NoNewDER portfolio that the previous ACC had been using.

6:22  
The second was that, well for this cycle, we are using an integrated calculation to derive both GHG and generation capacity, what it calls in.

6:34  
Previously the two value streams were calculated interdependent independently and I will have a section dedicated to that to describe what we did.

6:45  
3rd, the server SERVM team updated their storage dispatch algorithm to better capture the flexibility of storage energy storage and this will have a direct impact of the generation capacity allocation factors and they will describe more how they did it later on.

7:06  
And then finally, SERVM team also did additional calibration and benchmark of their cost modeling results with with the historical results.

7:16  
And finally, we also move the refrigerator of what it cost calculator to the DDR proceeding in terms of the transmission and distribution of what it cost.

7:27  
There was no methodology change.

7:30  
We made a few updates on the data and make sure that the methodology is aligned with the 2019 distribution white paper methodology.

7:42  
And finally, starting in this cycle on the 2024 ACC now includes a societal cost test or SCT option.

7:53  
In that the ACC we used to do now is referred as a a total resource cost or TRC perspective.

8:02  
Now the users will be able to toggle between both perspectives in the electric and gas model.

8:09  
All right, so that's kind of a summary of what has changed.

8:15  
Let's move on to the next slide.

8:18  
All right.

8:19  
This slide describes the first key change of the 2024 ACC.

8:26  
That is instead of using the no new DER portfolio, now the ACC is based on the IRP latest adopted system plan or the 2023 PSP for this cycle.

8:40  
We think that this is one step further in the direction of aligning the ACC and the IRP or the long term bulk grid planning.

8:50  
There are several components in the ACC that are closely aligned with the IRP PSP.

8:57  
For example, the portfolio produced by the PSP by Resolve is also simulated in the server to produce the energy avoided cost, and so the outputs by Resolve and server are also used in the integrated calculation.

9:16  
For example, the resource cost, the resource energy value and resource GHG and capacity contributions that are used in the integrated calculation either come from the Resolve IRPIRP, Resolve modelling or server modelling.

9:31  
And finally, a few generic general inputs are aligned between the ACC and IRP.

9:38  
So the picture on the right shows the capacity addition from the newest PSP case.

9:48  
The key take away is that the PSP case is planning to build a significant amount of solar marked in orange and storage marked in purple.

10:02  
And overall we see that the California system would see a pretty dramatic transformation in the next few years.

10:17  
All right, let's move on to the next slide.

10:22  
OK, so this slide summarizes the result difference between the I'm showing.

10:34  
At the bottom are the 20 year levelized values for all the all over the cost components for a resource that's installed in 2024.

10:47  
There are few differences between the 2022 and 2024 ACC.

10:54  
The 1st is the energy of what it cost or energy value.

11:00  
It becomes more time dependent in the 2024 ACC.

11:05  
What that means is that we see that the energy voting costs are lower in the middle of day and then higher overnight and in early mornings.

11:14  
We also see higher GHG values in 2024 ACC that are mostly concentrated in the evenings and early mornings.

11:23  
That's because the GHG emissions are directly related to the energy prices.

11:29  
So when the energy prices are high, the GHG emissions are also high.

11:33  
So the GHG value is that that's where the GHG value is high as well.

11:39  
And conversely, we see that the compared to 2022 ACC, the generation capacity costs are lower and also spread out in more hours.

11:49  
And finally, it's very hard to see it here, but the distribution values is much lower in the near term, but overall it's doesn't see a much difference in the long term.

12:02  
And the Andrew Sofas, my colleague will describe a bit more on that later on.

12:09  
All right, let's move on.

12:12  
So that the slide I just showed before shows kind of the overall of what it cost.

12:18  
E3 also plugged, plugged in the avoided cost to evaluate a few example Ders and I want to go over the results of a few of them.

12:29  
We'll start with the load reducing Ders.

12:31  
So here the chart I'm showing is the 20 year level as the value for a 2024 resource or resource that's installed in 2024 and last for 20 years.

12:42  
The difference and then showing side by side comparison between 2022 and 2024 ACC from left to right is the residential cooling, solar, solar and storage and flat.

12:55  
Flat here means that there's a same amount of load reduction like across all hours.

13:03  
The key takeaways here is that the flood avoided costs have increased mainly because of the energy and GHG avoided costs.

13:15  
However, the avoided costs during middle of the day have decreased and that's why we see that for residential cooling, solar and solar storage, the avoided costs are slightly lower compared to 2022 ACC.

13:29  
And that's really because of that time dependence change in in the energy as well as the GHG over day cost.

13:38  
In terms of the ratio between different components, we see that the GHG value has increased for 2024 ACC while the generation capacity value has decreased.

13:50  
So as I was saying, the for the load reducing DERs that generate during mid of the day, we see that the boarding cost has slightly decreased.

14:02  
But let's say if we plug in a DER that reduced load during middle of the night or early mornings, we would expect that avoiding cost of those DERs would increase just similar to Callaway flat as illustrated in the flat version.

14:20  
All right, let's move on to the next slide which is a load increasing DERs.

14:26  
So here we are also plugging a few examples for load increasing DERS.

14:33  
From left to right is the residential heat pumps.

14:36  
The EVs and flat know that the chart here represents the marginal cost rather than avoided cost for these DERS.

14:46  
So looking at the residential heat pumps, we see that the cost are slightly higher during the winter because of the energy and GHC adder values increase.

15:01  
But then if you were you were to plot this for the summertime, the cost would decrease because the cooling load typically coincide with like more in the middle of day rather than evening.

15:16  
But overall, when we combine the summer and cool and winter load, we see that for a residential heat pump, the cost slightly increased compared to 2022 ACC.

15:29  
And then in terms of the EV, we see that the cost are much higher compared to 2022 ACC.

15:35  
And that is because the EV load shape we assumed here mainly charges during the middle of the night and early morning.

15:46  
But if let's say, if we were to plug in an EV shape that mainly charges during middle of the day, we would expect that the cost of this EV shape would decrease.

15:57  
So it's really depending on the the low shapes that we assume for each example der.

16:03  
But in this case we see that EVs see higher cost if it charges during mid of the day and early mornings.

16:14  
That's kind of a summary of the electric model.

16:18  
Let's move on to the next slide.

16:20  
We have one small update for the gas model.

16:23  
So for the 2024 ACC, there's no methodology update for the gas model.

16:30  
We did update a few data points listed here, including the gas price forecast or gas commodity cost, the avoided gas infrastructure cost, the gas transportation marginal cost, and finally the IOU weighted average cost of capital.

16:46  
The charts I'm throwing right compares the NU Gas avoiding cost between 2022 and 2024 ACC.

16:55  
And you can see that compared to 2022 ACC, the 2024 one increased slightly especially in the near term and that's mainly driven by the high higher gas commodity cost.

17:09  
And the chart on the bottom right shows compares a kind of a monthly shape or monthly avoided cost for year 2024.

17:18  
The two ACC versions show similar shapes across the year.

17:26  
That concludes the overview kind of resolve overview for the 2022, sorry 2024 ACC in the electric and gas model.

17:37  
And now I'm going to turn over to the SERVM team to describe the SERVM data update.

17:43  
OK, fun thing.

17:45  
Thanks for that.

17:45  
But first we want to get it.

17:47  
Oh, sorry for folks to answer questions and have.

17:50  
Yeah, So just questions always.

17:53  
Yeah.

17:53  
Just so everyone knows, I'm first going to go through Q&A questions.

17:57  
We'll read them out loud so everyone can hear and then we can answer those and then we'll go to hands raised.

18:03  
In this case, we don't have any Q&A questions, so we can start with hands raised.

18:08  
If you could announce your name and your organization when I unmute you, that would be great before you ask your question or write your comment.

18:17  
So I will start with our first hand raised.

18:21  
We have Tom Beach here.

18:23  
Tom, you should be able to unmute yourself now that I have requested to unmute you.

18:36  
Hello.

18:36  
Can you hear me?

18:37  
Yes, I can.

18:38  
OK.

18:39  
Thank you very much.

18:40  
This is Tom Beach.

18:41  
I'm a consultant to the Solar Energy Industries Association.

18:44  
CF I, I noticed that I, I think it was your first slide said that, you know, the draft that you've released on the 2024 ACC is based on the staff proposal and the proposed decision.

19:01  
Yes.

19:02  
And yeah, I just want to ask that obviously I think you referenced what's been adopted in the proposed decision and you know, proposed decision is just that it's not a final decision.

19:18  
The proposed decision still has yet to be voted on by the Commission and some quite a few parties are recommending changes in the proposed decision, including changes that could have a non trivial impact on the 2024 ACC numbers.

19:42  
So I, I just wanted to raise that and ask, you know what, what's going to happen if the final decision on the 2024 ACC differs from the proposed decision?

19:57  
And how will parties know how those changes affect, you know, the values in the 2024 ACC?

20:08  
Will there be another workshop?

20:09  
Will there be a republishing of the draft?

20:13  
It's very unusual and.

20:17  
Different than past ACC processes to have a draft released before the Commission has finalized the policies and methodologies that are used to the ACC.

20:31  
Great, Tom, thanks for that question.

20:33  
I would note that what's on the side is just the literal title of the proposed decision.

20:38  
So the term adopting is there and it wasn't meant to imply that it is, has in fact already been adopted.

20:44  
It is in fact a proposed decision.

20:46  
As for the rest of your question, I would turn it over to Stephen Neal, who is one of our panelists from the Energy Division who can speak to that.

20:55  
Stephen, are you able to unmute yourself?

20:58  
Yeah, Yes, I am.

21:01  
Yeah.

21:01  
So we've received note of your concerns both in the letter that you had recently sent and have taken that under advisement.

21:12  
And at this time, like I said, the proposed decision is out there for public viewing as are all the comments that people should be able to judge for themselves in the comments what the potential pathways may be.

21:25  
But they are in general, we believe enough information is out there for us to proceed.

21:31  
And if further comment is needed after the finalized decision is released, then we can talk at that time.

21:41  
OK, thank you very much.

21:45  
OK, great.

21:46  
Let's go to the next raised hand.

21:51  
Gene, you should be able to unmute yourself.

22:04  
Hello.

22:05  
Yep, hello.

22:07  
Yes, Gene Armstrong also with the Solar Energy Industries Association.

22:11  
I, I have a question, but I also have a comment to follow up on what Tom was speaking to.

22:18  
Actually in the procedures that were laid out in the 2022 ACC decision, you know, the Commission adopted some more process around the ACC updates and, and it very clearly says that the, the draft, the model ACC is supposed to come out after the decision and the workshop is supposed to be held after the final decision.

22:41  
So by doing it in this in, in this order that is you've undertaken this year, it's not in compliance with the Commission's 2022 ACC decision.

22:51  
So I'm just going to put that out there for you guys to consider.

22:55  
I then also do have a question.

22:57  
And it's also on that first or the slide that's currently on the screen the bullet or the cross sign that says transmission and distribution avoided costs were updated based on the latest utility filings etcetera.

23:14  
With respect to the transmission costs, what exactly what data did you use for Southern California Edison and San Diego Gas and Electric?

23:29  
And I'm just talking about the transmission piece right now, Andrew, if you wanted to answer that question, I will say that we are going to get into this in detail, but we'd be happy to touch on that briefly now, Andrew, if you wanted to answer that question on transmission costs, Yeah.

23:46  
So we use investment data from the utilities.

23:49  
It's basically following the discounted transmission investment method and the LMBA approach as we've used in the prior AC CS.

23:59  
The methodology hasn't changed, but yes, we'll, we'll get into that a little bit later on.

24:05  
Be happy to, to talk through that generally.

24:08  
And then the load data, which supplements that comes from public sources from CAISO EMS data set primarily, but we'll touch on that later as well.

24:19  
Yeah, I'll, I'll listen to the presentation and then I'll follow up then if I have additional questions.

24:23  
Thank you.

24:30  
Great.

24:31  
OK, let's go ahead and go to the next hand raised.

24:36  
Damon, you should be able to unmute yourself.

24:39  
Jean, if you could actually wait, I think I can do that.

24:42  
There we go.

24:48  
And France from Tesla.

24:50  
I actually have two questions.

24:52  
Maybe I'll, I'll post the first one and then and then the second one.

24:56  
The first one is that the 2024 ACC produces some pretty dramatically different numbers and dispatch signals from the 2022 ACC.

25:07  
Seems like a lot of it is driven by the integrated calculation of capacity and GHG.

25:15  
You know, capacity in the IRP is procured both for reliability and for GHG emissions reductions.

25:20  
And so I guess it's not clear to me how you would distinguish between what's procured for capacity value versus what's procured for GHG emissions reduction.

25:30  
Is it possible to sort of explain how that how those values are sort of split out?

25:47  
This is function.

25:49  
Great question.

25:50  
We'll have a whole section dedicated to that.

25:52  
So I'll make sure to work through our methodology.

25:55  
And if you have further questions, definitely happy to chat through that during the discussion.

26:00  
Would that work?

26:01  
Yeah, that that's fine.

26:03  
My other question is about the load increasing DERs.

26:07  
I've been somewhat confused about that for a while since you know for the purposes of grid planning you know you have load and then you have resources that are procured to serve that load like an integrated resource plan.

26:20  
It's you know all generating capacity resources.

26:23  
So having some load increase load considered to be also a resource seems pretty confusing and I'm I've never been sure what the purpose of it is.

26:34  
Like is there some policy decision that can be made from knowing what the value of a load increasing DER is?

26:41  
Like I'm not aware of any incentives or anything that that information would inform.

26:46  
Is there something that that information is informing?

27:03  
This is Dan Buch.

27:04  
I think the one of the things that's informing is the cost effectiveness of fuel switching.

27:10  
We need both the costs and the benefits on both sides when we do fuel switching.

27:13  
Those are within the Commission's portfolio programs.

27:16  
So it is important to have both the load increasing and load decreasing contributions.

27:37  
Great.

27:38  
We don't have any other hands raised.

27:40  
So to keep us on schedule, I think we should, yeah, go to the next session if no one opposes.

27:46  
All right, great.

27:49  
Thanks, Alex.

27:52  
Hi, everyone.

27:53  
My name is Mounir from the CPUC Energy Division.

27:57  
The presenting here about the work we did to support the ITC.

28:03  
Next slide please.

28:07  
Yeah, we'll be talking about like mainly three-part of it.

28:10  
So one the backcasting, the forecasting price and then the loss of load analysis.

28:17  
So and backcasting, we'll show you the major updates inputs and the major updates to the SERVM clients.

28:25  
The SERVM client is the production cost model we use here.

28:30  
We also talk about the calibration within to align the SERVM price with the CAISO actual prices and we'll show you some graphs about the price and then maybe like how with our analysis, I will benchmark our analysis.

28:50  
Then we move on to the forecast in parts.

28:53  
So when the forecast is sent, first one we need we forecast the price from 2024 to 2045 years in the team.

29:02  
Why typical meteorological year using SERVM model again?

29:07  
So the main take away from the forecasting part is that like the energy and the ancillary prices were elevated for the first few years then moderate after 2027, but again the get elevated in 2040 and 45.

29:26  
The rising of the demand, the price trend is overall is reasonable and and that's what we expected in term of the loss of load there is a trend.

29:39  
So in the next term, next term they were like high, they were lower next term but did get higher a little bit out to 24.

29:49  
So the decrease import levels and tightens supply demand balance in the outside area.

29:56  
And last to one is about the loss, loss of load expectations.

30:02  
So that is going to be the next presentation, second presentation where we show you the loss of load using two routines of the storage dispatch, the 1st, the regular one we use in our production cost and the new storage dispatch.

30:18  
So next slide please.

30:22  
So we'll start with the backcasting.

30:24  
Excuse me next one please.

30:27  
So the main take in the back that's in here.

30:30  
So what we did, we'll start by the data collection, that's the first thing.

30:34  
So we mainly collected data for 21 and 22 data for electricity prices, the demand and supply side as well as the import, export, solar, wind and hydro.

30:47  
This come from CAISO website.

30:50  
And then we collected the good data using the NGI for 21 and 22 again.

30:59  
And the generation data we use also the data set from CAISO called the settlement data set.

31:08  
After data collection, then we'll process data using different like software like R, Python, Excel and then different approach to get the data, final format the report and SERVM.

31:26  
Once they can serve them, we'll start running the model.

31:30  
So and then we start with like an initial calibration like we just use what we say here, island models like we use CAISO so as one block, not like 3 regions.

31:41  
Then we include other regions and then we do calibration.

31:46  
So we're on the model.

31:47  
If we're not happy with it, then we're just and so on.

31:50  
So some adjustments include like heat rate, transmission constraint, gas price etcetera.

31:56  
And then also we made it's not an adjustment but we're aligned with CAISO prices.

32:00  
So we use like what we call soft cap.

32:03  
Soft cap is like the price Max at $1000 per MW hour, but there is also a hard cap of 2000.

32:14  
So also we constructed like what we call scarcity pricing curve and it's like basically an A function that decays exponentially but it's got at $2000 per MW hour.

32:27  
The reason again is 2000 is like the hard cap.

32:32  
So here and the SERVM model we use has got updated and there is there is several updates.

32:41  
Yeah, Yeah.

32:46  
So there was some update in the SERVM model.

32:50  
There are several of them, but like here Willis is like few that's relevant to the ACC like the added then it's a present value to calculate for the future year system cost.

33:03  
Also there is another option added about like the ORDC, the operating resource duration curve, the demand curve, sorry.

33:14  
And then also there is another storage logic.

33:18  
There is another option about to model daily fuel prices and curtailment.

33:26  
And the last one is an option to use routine to dispatch the storage.

33:33  
That is going to be again the 2nd presentation.

33:36  
There are so often there's the one we use on a regular basis and there is the one we're going to construct contrast the original approach with and that's going to be again in the second presentation, the next one please.

33:57  
So, yeah, OK.

34:01  
So yeah, so there is some analysis with it and some benchmarking.

34:04  
So basically what we did, so we did like a analysis of the SERVM price again, the actual CAISO prices for 2021 2022 for both energy and ancillary services.

34:19  
We use different approach, the secret approach and also we look at distribution further and trend analyze like each hour day, each month of the year, we use the inflate right and direction curve.

34:35  
We'll look at the density distribution for SERVM and CAISO.

34:42  
And then we'll look at we evaluate the major difference using like hourly load.

34:50  
And then we use what we call like the mean absolute error to to look at how good we are with our forecasting.

35:00  
So the next slide, please.

35:04  
So here we're showing you in this slide comparing like the energy price from SERVM in red to CAISO energy price is in the blue.

35:12  
The CAISO is orange.

35:15  
So the bottom, the X axis is the hours is like from zero to 24.

35:22  
The Y axis is average price.

35:24  
So you see here that the general trend is, is I would say relatively aligned in indicating there's a good calibration of the model to actual world prices.

35:35  
So there is like there is a slight discrepancy in month 9 like hour 19, hour 18 to hour 19.

35:44  
And that's the scarcity price curve we constructed.

35:50  
Yeah.

35:50  
So in general, the model, the SERVM model is generally well calibrated.

35:54  
So next slide, please.

35:58  
There's another, just another QC or rather another like chart to show that the model is well calibrated.

36:06  
So this is our Operating reserve duration curve.

36:10  
And he wants to repeat what we just said that it seems like we're breaking up our audio.

36:15  
Oh, so just yes, say it again, which one?

36:19  
I guess this part, the price, yeah, that we, we performed this calibration.

36:26  
As you see, in general, our price patterns seem to align well with the CAISO prices.

36:34  
There's some elements to the CAISO prices that are not represented by our model.

36:41  
You can see some events in December there, you can see some events in September.

36:47  
But the overall point of this slide is to show that in general, our price patterns correspond to ISO prices.

36:57  
Yeah, yeah, I'd just like to confirm that point.

37:01  
Like here we're showing you this, the duration curve of SERVM and CAISO price for 2022.

37:08  
So SERVM is in the blue and CAISO is in the red and it's very much aligned.

37:14  
So you can see there is a slight deviation, but like overall it's like it's we're calibrating.

37:19  
So this is like the price and then we’ve ranked the price from the highest and the lowest.

37:24  
The X axis again, is the ranking of the hour 8760 and left or the Y axis is the is the price.

37:33  
So at the higher end, the price runs for far right, duration curve when there is some event of higher you know of higher prices if you look between the range 500 to 50 and SERVM a little bit under predicted like those peaks compared to CAISO.

37:55  
But the majority of the time in the middle from the middle the right the price, the price seems aligned very well.

38:06  
Sorry, we have an air conditioner going in this room which makes for a bunch of fuzz.

38:13  
So just let us know if you ever want us to repeat anything.

38:17  
Yeah, otherwise we'll just move through.

38:20  
There's a lot of material here.

38:22  
Yeah, we're just trying to hit everything.

38:24  
So keep going.

38:25  
Yeah.

38:25  
So just so the bottom line of this is like the duration curve indicate that SERVM model is well calibrated to reflect the CAISO market price across most of the range of the price.

38:37  
So once we get confident in our price, then we move the next phase which is forecasting.

38:43  
Can we move the next one please?

38:46  
Slide Yeah, forecast.

38:48  
Thank you.

38:49  
So the forecast in the for the forecasting there is so we need to we need to change some inputs there.

38:55  
And the main one are like the demand forecast, we use the IEPR and then we use the fuel price for the future reason, the NAM gas price and then outage data, we use the current outage data from SERVM to anticipate the potential distribution in the power generation.

39:14  
Also we use the we adjust the supply side using the IEPR forecast.

39:19  
And then when assembling the price, we use the 8760 strip based on the TMY data on the table on the right show the reference how we assemble those price.

39:34  
So for example, we'll get like the we use the weather the year 2004 to get the data for January for the first month and then we continue until we assembled the 8760 strip of the of the price next one.

39:53  
Yeah.

39:53  
And aside from certain changes made because of back casting adjustments, primarily the scarcity price adjustments that we talked about, everything here is sourced from the data set that gave us the IRP preferred system plan.

40:12  
So the same IEPR or the same outage data, the same fuel prices and all that stuff.

40:16  
exactly.

40:17  
So this slide we're not showing you everything we did because there's a lot of material, but located like some there's some comparisons.

40:24  
It was showing you the price for 2030 and 2024 for like second month July, August, September and October.

40:33  
So you can see the price go below 0.

40:36  
But like in the ACC costs have a floor at 0, meaning no cost go below 0.

40:41  
But it's like what the price were predicted what forecast from SERVM.

40:46  
So, but so in 2030 you see the peaking early morning and late afternoon corresponding the high demand time, net demand, net demand time, you totally see what solar is doing in the middle of the day.

41:02  
So the net load, so the price decrease there in the midday from 2030 to 2024 the solar generation against all of us and increase at next time our early morning so that driven by mainly by the EV demand which grows as time goes further out if you have 2040 streamed in 20-30.

41:26  
So, but the daily fluctuation is consistent with the platform expected.

41:32  
So to so next slide, please.

41:36  
So the next one is just like again.

41:39  
So this link just like to show the point we make early that like there's the 2024 including the price and the late night and early mornings driven by the EV.

41:51  
It doesn't show when you get a comparison.

41:53  
And so this, yeah.

41:57  
So,the blue line is 20/30/24 is orange, 2045 is, is the green.

42:09  
So you see, as time goes, the increase of the EV demand, there is an increase of EV demand.

42:18  
And you see what time of day it is.

42:19  
There's an awful lot of EV demand late at night when the sun's down, so you can see how overnight you're increasing your reliance on things that aren't sun.

42:31  
Yeah, and a lot of the batteries have been expended already.

42:34  
They're mostly handling that net peak 19 20 21 22.

42:39  
So the 23 24 1 2, that's all going to be stuff that ain't batteries too.

42:44  
So that's where a lot of the late evening prices start to escalate.

42:50  
A question is like.

42:51  
And so how does TMY work?

42:54  
TMY means that we will run the model, produce prices for all our weather years and then stitch together, you know, 2004’s January, all that weather year.

43:07  
Then the next month, February comes from a different weather year, then the March comes from a different weather year.

43:12  
And you literally just stitch them all together, you know, to make a 12 month, a single 12 month strip of prices. That TMY was actually picked I think by somebody who's not us, I don't know who, but somebody who's not us picked those TMY months at least two years ago because that is the same TMY pattern that we that we used in the previous ACC.

43:37  
We think it's an average weather year and we think it's meant to be an average weather year.

43:41  
Like it's meant to be kind of a middle of the road weather year, not extreme.

43:45  
Yeah.

43:47  
So that's how it's picked.

43:49  
That's what TMY is supposed to be doing.

43:51  
And so the way we did that is we just ran all the weather years.

43:54  
You take all, you know, 1 2 3 4 all through 31 January and then take all the results from the next month, stitch them together, then you take the next month, stitch them together.

44:04  
So you have this kind of Frankenstein 12 assembled months from all the different weather years.

44:09  
So it makes sense that there's some like weather, like some like extremities like, you know, yeah, we're going to pick a moderate summer and a pretty moderate winter.

44:19  
Maybe those don't really occur in the same year where you have a cool summer and a fairly warm winter.

44:24  
Maybe you don't normally see that really in a weather year.

44:27  
But the way we assembled it, that's what we're trying to get to.

44:31  
I hope that answers the question.

44:33  
All right, yeah, next slide, please.

44:35  
So next one is about the implied heat rate just to show how the EV impact the price.

44:43  
So this slide is the blue line is 2035, but it's the same as 2030.

44:49  
So we can provide the data is needed.

44:51  
But like the it's the same idea, the same patterns.

44:55  
So the, the green is the 2045 and then orange again it's 2040 and then you see like those high implied heat rate is indexing either early or like late at night that's driven by the EV and that's it which required like additional like thermal generation which is increasing.

45:15  
That's why you see the increase price and that's reflected in the implied market rate.

45:18  
It seems to suggest that if we were doing a net market value from 2024 to 2040 EV would cost a lot less.

45:27  
But including way out to 2045, you get a lot of these money pricing that really ramps up after 2040.

45:34  
So the next slide please, the next slide just showing you here like a heat map of the spin price for 2030 and you see the like an average like the spin price is 6.40 dollars and that happened in hours and ending 16 to 21 particularly in like August and July.

46:01  
So at this what was in the market and this price are due to scarcity pricing which increases price when supply side and demand is high to reflect the scarcity of available resources.

46:14  
So this frequency of high spin price aligned with peak demand periods indicating that the scarcity pricing mechanism are reflected in the period of time of supply and high demand, which keep us confident in the model.

46:32  
The next one, last one last slide please.

46:36  
So this slide is just like to show you some of the, the QC, the quality control we do to keep confidence in our pricing.

46:44  
And this, this graph is just scatter plot is the correlation between the market price and the net load.

46:52  
The net load is at the X axis, the market price is the Y axis.

46:58  
And as you see, there's a show a strong force of correlation between the market price and the net load, indicating that the market price increases as the net load rises.

47:14  
So the last thing I will make is this alignment of scatter plot servm market prices and net load suggested to us that the model accurately captured the relationship between the net load and the market price, demonstrating that a good predictive accuracy of the servm model.

47:32  
So that was my last slide.

47:34  
But just to recap, we did like three things like first thing is, is, is back testing to calibrate the the 2021 and 2022 with the actual price of prices.

47:44  
Once we get confident in the pricing, then we forecast the price from 2024 to 2045 using TMY.

47:53  
And then the last part we forecast that and we model the loss of load and the loss of load using two routines of storage, the regular one and the new one.

48:06  
And that will come up in the next presentation.

48:10  
And thank you.

48:15  
OK, great.

48:16  
We can open the floor for questions and discussions.

48:20  
I think the questions have been answered in the chat.

48:22  
So let's go to Raised Hands.

48:25  
We can start with Tom Beach.

48:29  
You should be able to unmute yourself.

48:32  
Yes.

48:32  
Thank you.

48:33  
Can you hear me?

48:34  
Yep.

48:35  
Yep.

48:37  
So thank you for presenting that back casting data.

48:42  
You know, we, we because the, the, the draft documentation that was circulated doesn't have any of the, you know, back casting information are you gonna make that available?

48:56  
And I, I'm asking because we did some back casting of the implied market heat rates from the, your SERVM runs not to 2021 and 2022, but to 2023.

49:10  
And our implied market heat rate duration curve for 2023 is very different than your SERVM results.

49:21  
And we'd be happy to provide that to you in, in particular, in the probably the 2000 hours, the 1st 2000, the 2000 hours with the highest implied market heat rates, the 2023 market heat rates were substantially higher than what was modeled in, in, in the SERVM runs.

49:47  
I, I don't know if that's an artifact of 2023 versus 2021 and 22, but it, it, it suggests that something needs to be, needs perhaps to be looked into.

50:03  
And then finally you, I think one of your early slides said that you did some root mean squared analysis of your benchmarking.

50:11  
Can you make those results available?

50:18  
We have produced a lot of back casting data and visuals.

50:25  
We are going, we, we're, we're planning to put out a subset of what we produced.

50:31  
We'll see when we can do that.

50:33  
Probably going, you know, if it's going to happen, it's going to happen pretty soon.

50:37  
We'll just see what all we, we, we will put out.

50:41  
I know that we had to put out some things like that list of servm, servm enhancements, that list of data updates.

50:48  
Now that it's in the slide deck, we had to put that out.

50:51  
We, we, we told you that we, we said we would put it out.

50:54  
So we reported it.

50:55  
But there's other things in that back casting document that we may be able to produce some of the results from 21 and 22.

51:03  
We'll see what we can do.

51:07  
And my, my final question is on this last slide here, how do you get a, a net load of -40,000 megawatts?

51:14  
I've never seen a net load that negative.

51:19  
How is that possible?

51:34  
So if you want to answer that, we'll take a look and get back.

51:57  
Yeah, we'll take a look at it.

51:59  
But that means that there's 40,000 megawatts more solar on the system than there is load.

52:06  
That seems it's gonna be like more renewables.

52:10  
Basically.

52:11  
There are certain various, but like you can, yeah, we need to see what, what, what driver, the main driver, the bulk of these, there's a, a large percentage of these data points are for net loads of -10,000 megawatts or more.

52:29  
And I, I don't know if I've ever seen a time when there were 10,000 megawatts more renewables on the California grid than load.

52:38  
I mean, so well, let's let's take this back.

52:43  
Yeah, there is some negative pricing and that's probably like that's what what happens because, you know, there's a lot of maybe like solar or other, you know, other production.

52:55  
So but yeah, we need to take the look at data and then we'll, you know, confirm what we said.

53:02  
Thank you.

53:10  
OK, let's go to the next question.

53:15  
You should be able to Yes.

53:20  
Hi.

53:20  
Thank you.

53:21  
I was going to ask regarding.

53:24  
Oh, just real quick, do you mind saying your name and organization?

53:27  
Thank you.

53:28  
Yes, sorry, Nicholas Fetty, Solaris technical consultant for some of the IOU’s efficiency support regarding, for example, the load profile for electric vehicles charging raises the question that will consumers respond to price signals.

53:52  
And you know, the possibility that there may be rate tariffs that help consumers schedule their usage in in response to the price, the real time price.

54:13  
So the possibility that there's a feedback between the price and the load.

54:19  
Is there any thought of maybe considering like an ensemble of different scenarios where those load profiles change or similarly, I mean, a secondary question like whether is one year of typical whether sufficient to kind of capture all the range of variations?

54:40  
And.

54:43  
Thank you.

54:45  
Yeah, in terms of whether one year of typical weather is enough to capture variation, probably not.

54:52  
That's, you know, we, you know, we'll take that. a different approach is possible where we can take a distribution of outcome and make a weighted average or some 70 50 30, you know, Box and Whiskers plot or some kind of distribution.

55:14  
We can totally do that.

55:17  
It's just that's not what the TMY approach is.

55:19  
So that's what we're using TMY approach for this.

55:22  
As to whether electric vehicle load can be priced responsive, I suspect it will be.

55:28  
It's just that what you're seeing here is that it doesn't really bite until much later in the horizon.

55:34  
So we'll see what happens as the magnitude of it gets higher and higher and begins to affect dispatch results.

55:43  
I'll make one point that the high prices don't mean that there's lack of capacity.

55:49  
It's just the capacity you get is expensive because it's not renewable.

55:55  
You see with the spin price that Mounir showed, that's when you run out of capacity, that's actual scarcity of capacity type pricing that you get in those net peak hours, you know the 18 to 22, 17 to 22 time frame, that's when you get shortage of actual capacity.

56:13  
The other one is just, you know, availability of capacity, just expensive.

56:19  
Those are two different situations.

56:20  
We'll talk more about loss of load in a later presentation.

56:34  
OK, I see no other hands raised.

56:37  
Hayley Fitzpatrick in Q&A did have a follow up in the discussion.

56:42  
Someone said that it was decided by others but no real details.

56:45  
This is the source of the CTZ weather years.

56:49  
Have the analysts involved on any sensitivities to test how the CTZ weather years would affect the results using different ones?

56:58  
I'm assuming is what she means.

57:15  
Mounir and Donald, I'm not sure if you're answering that question.

57:19  
Great.

57:20  
Well, I mean the TMY was, you know, is a holdover.

57:25  
But I think I originally I my memory at least is that a source from Energy Commission modeling several years ago.

57:35  
But our yeah, but, but, but it wasn't, it wasn't part of our work to evaluate it and to or to or to redo it.

57:49  
It was just, it was something it's again, it's the same TMY that was used two years ago.

57:55  
So, you know, same one that was used two years ago.

58:14  
OK, it looks like there are no other hands raised.

58:21  
So I think we can move to the next section if there's no objections, right?

58:28  
So we can turn it back over to Fanxing.

58:30  
Great.

58:30  
Oh, mm.

58:34  
Hmm.

58:42  
Right.

58:43  
Let's try this way.

58:44  
Can people hear me?

58:45  
All right?

58:46  
Yep.

58:46  
OK, Awesome.

58:47  
Awesome.

58:48  
Great.

58:48  
Because I just switched my audio.

58:50  
All right.

58:52  
For the next few minutes, I'm going to go over the integrated calculation of generation capacity and GSG of what it cost.

59:01  
I will use a few slides to describe the methodology and the principle behind it.

59:08  
Hopefully, it will be a reminder for most of the folks since we presented in the 2024 staff proposal last October.

59:17  
And then I will jump straight to the results that are coming out of the integrated calculation.

59:22  
So that will be the annual GHG and capacity avoided cost.

59:27  
All right, let's go to the next slide please.

59:33  
First one to provide kind of the principle behind this approach.

59:39  
Essentially, the core principle of the integrated calculation is that for each supply side DER resource on the margin, the total resource value should match its cost.

59:51  
This can be really illustrated in the graph below.

59:55  
We're seeing that each supply side resource is filled to meet three main system needs.

1:00:01  
They provide energy, they provide capacity, and then they support California's GHG reduction goal.

1:00:09  
The integrity calculation really aims to calculate GHG and capacity body costs such that the total value provided by each resource is able to cover its revenue requirement or cost.

1:00:23  
So here the energy value comes directly from the serving prices that Monia and Donna just shared.

1:00:31  
And then the integrated calculation calculate the GHG and capacity of what we call such that the value is equal to to cover the gap between the resource revenue requirement and energy value.

1:00:50  
And that gap is usually what we call the missing money of each resource.

1:00:57  
This model aims to capture two fundamental dynamics in the long term resource planning.

1:01:04  
First is that the three value streams, the energy, GC and capacity values, those are interactive and interdependent because the electric grid really needs all three, you know, decarbonized world.

1:01:20  
And the 2nd dynamic is that multiple resources can provide multiple value streams.

1:01:26  
For example, solar we know typically is built to help achieve California's GHG reduction goal, but also it can provide some capacity contribution during kind of the late late afternoon, early evening time frame that sun is still up.

1:01:45  
For the 2024 ACC.

1:01:47  
The integrated calculation uses 3 representative resources to derive the GHG and capacity avoided costs.

1:01:54  
So that is a generic utility scale solar, a generic lithium ion battery storage.

1:02:01  
It can be 4 hour or eight hour depending on which year it is and when the IRP use storage.

1:02:10  
And the finally, the cost of maintaining existing gas plants is also considered in the calculation.

1:02:17  
More specifically, the floor of the capacity avoided cost is said to be the O&M cost of maintaining existing gas plants.

1:02:30  
All right, let's move on to the next slide.

1:02:35  
This slide is essentially an equation version of the concept I described earlier.

1:02:42  
We're showing that the total resource value provided by each resource should really be equal to the resource cost on a net present value basis.

1:02:52  
So the left side of the equation is a resource cost, it is represented as levelized fixed cost that are aligned with the CPUCIRP proceeding.

1:03:03  
And then the right hand of the equation is the value of the resource.

1:03:08  
So we can divide them to energy capacity and GHD value.

1:03:11  
Energy value is calculated using the serving prices or energy awarded cost.

1:03:16  
The capacity value is equal to the marginal capacity contribution of each resource multiplied by the capacity awarded cost that the integrated calculation will derive.

1:03:28  
The marginal capacity contribution or marginal ELCC is the same as what's being modelled in Resolve for the IRP portfolio.

1:03:36  
And then for the GHG value is equal to the marginal GHG contribution of each resource multiplied by the GHG avoided it cost.

1:03:46  
And we derive the GHG marginal impact using the SERVM prices or SERVM energy prices or SERVM implied heat rates.

1:03:56  
We basically multiply the implied heat rate by the carbon content of gas plants to derive the system marginal emission rates.

1:04:04  
And when they multiply, when we multiply the system marginal emission rates by the resource generation, we get the GHG contribution of the resource.

1:04:14  
So that is kind of what is the emission rates, the emission that a resource is able to avoid from the supply side.

1:04:26  
For more details of the calculations step by step, please refer to the documentation we published.

1:04:35  
We described how we got to each step and then the data sources we used step by step.

1:04:42  
But for the interest of time, I'm going to jump straight to the results so that we can have a discussion later.

1:04:51  
Let's move on.

1:04:54  
First, I want to show the comparison between 2022 ACC and 2024 in terms of the annual GHG, avoided cost.

1:05:05  
These are the.

1:05:07  
This includes both the cap and trade price as well as the GHG adder, but it doesn't include the GHG rebalancing.

1:05:17  
So we see that compared to 2022 ACC, the GHG avoided costs for 2024 have increased and that's due to a combination of reasons and want to explain each of them very clearly so that people are understanding.

1:05:35  
First is related to updated methodology.

1:05:39  
This is really less to do with the integrated calculation that we're using for this cycle, but rather just simply for 2024 ACC, we are calculating GHG and capacity avoided costs in each year explicitly.

1:05:55  
Well as in 2020 to ACC, the GHG avoided were based on one single value in 2035 and it was escalated or de escalated for for other years.

1:06:09  
So that methodology update that that methodology update was mainly due to now we are calculating avoiding costing every year rather than just one year, especially for GHG.

1:06:23  
The second reason that we see higher GHG avoided cost was really because of the high cost for solar and storage that have increased since the last IRP.

1:06:34  
The chart on the bottom left compares the solar level as fixed cost by vintage between the 2023 IRP that's the basis for 2024 ACC and the 2021 IRP that was the basis for 2022 ACC.

1:06:53  
We see that the levelized cost have increased especially before 2035.

1:07:00  
And if if you go back to the equation I shared earlier that the value should equal to the cost.

1:07:06  
When we see cost rising, the integrated calculation will need to increase the avoided cost to be able to match that cost part of the equation.

1:07:19  
And finally, we also see that the most recent IRP, the 2023 IRP is planning for a more stringent GHG target compared to 20/21 or previous IRP.

1:07:36  
For reference, the current IRP is planning for a 25 metric million metric ton metro metric ton in 2035, which is much more stringent than the 35 MMT by 2032 in the previous IRP.

1:07:54  
And that more stringent GHG target has two major impacts.

1:07:59  
The 1st is that with a more stringent target, the IRP is investing more expensive resource cost.

1:08:08  
That's again kind of an increase on the cost side.

1:08:11  
And the second major impact is that we as we try to as the state trying to meet a more stringent target a incorporates more renewable, especially solar in the system.

1:08:23  
And with higher renewable and higher solar, the marginal energy value or GG contribution for the next unit of the solar or the marginal unit of the solar is decreasing with this higher solar penetration.

1:08:38  
This, you can think of this as the as we increase more and more solar and the belly of that dark curve is getting more and more negative or lower and lower.

1:08:49  
So the chart on the bottom right compares the solar energy value between 2020 using 2022 ACC energy avoid it cost versus 2024 ACC energy avoid it cost.

1:09:04  
So you'll see a pretty big gap between the two versions and that directly contributes to a high GHG avoided cost coming out of the integrated calculation.

1:09:15  
All right, let's move on to the capacity side.

1:09:23  
Same charge on the top right.

1:09:26  
Comparing the 2022 ACC and 2024 ACC capacity of what it cost, we see that capacity avoided costs have decreased and that's mainly because with the new calculation, we considered the interdependence between and capacity GHG and energy void costs In particularly the now the 2024 ACC consider the GHG value provided by storage, whereas in the 2022 ACC, we only considered energy and capacity value for storage for the margin unit of storage.

1:10:07  
I also want to use the chart below to illustrate one key observation we had while implementing this model.

1:10:16  
That is, we saw that the storage energy and GHG value exceeds its cost and this is because of two reasons.

1:10:26  
The 1st is that the SERVM energy probe prices provided a lot of energy arbitrage opportunities for storage and that directly drive up the energy value for storage.

1:10:39  
And the 2nd is that the GHG avoided cost needed to cover solar missing money we saw that are more than enough to cover storage revenue requirement.

1:10:50  
And because of this the capacity of what it cost, storage doesn't need capacity avoided cost or capacity value and therefore the capacity of what it costs are at floor in most of the years.

1:11:05  
All right, let's go to the last slide.

1:11:08  
This is my last one.

1:11:10  
This kind of the chart I'm showing here basically further illustrate the point I was making earlier.

1:11:17  
So what I'm showing here are the net present values of revenues or values and costs for each resource vintage.

1:11:27  
So solar vintage 2024 here means a solar resource that spilled and started generating in 2024.

1:11:36  
And then this solar resource will provide energy GHG and capacity value during its lifetime for the next 30 years.

1:11:44  
So the bar that you're showing that you're seeing here basically represent the net present value of all those value added together.

1:11:54  
You can see that the energy capacity and GHG values match solar cost but exceed storage cost.

1:12:05  
And that's because as I was saying, the high energy value or and the GHG contribution of storage due to the SERVM energy prices or energy avoided cost and also the high GG woody cost driven by solar missing money.

1:12:23  
So that's kind of a brief overview of the integrated calculation.

1:12:29  
Definitely happy to answer questions and then have a discussion.

1:12:35  
Great, thanks.

1:12:36  
Fun thing, let's start with the chat.

1:12:39  
There's just a few questions in there and then we can go to hands.

1:12:41  
Hayley Fitzpatrick asked, are these GHG avoided costs the same in both the gas and electric models?

1:12:48  
It is not.

1:12:50  
For the gas model we used there, we used an intermedium approach.

1:12:57  
Basically we used carbon abatement cost of residential electrification as an intermediate interim value in the early years and then we escalated for later years.

1:13:11  
So it is different between the electric and gas model.

1:13:19  
And then on Slide 30, Sam White has a clarifying question shows that cost equals value.

1:13:25  
Do you mean avoided cost equals value?

1:13:33  
In this case the avoided costs are values and you can almost think like the right hand of the equation basically are avoided cost and then the rest the left hand side are cost.

1:13:49  
So that's kind of the dynamic the model wants to aims to represent here.

1:13:55  
That is we want to make sure the avoided cost match the cost of the marginal resources.

1:14:01  
Not sure if that helps.

1:14:03  
Happy to clarify further.

1:14:12  
Yeah.

1:14:12  
Sam, go ahead and raise your hand if you need further clarification there and I can unmute you.

1:14:20  
In the meantime, let's just handle this last question in the chat from Desiree Wong.

1:14:25  
Question is what ELCC values did E3 slash staff use for this analysis?

1:14:30  
Did they calculate the new ELCCS based on the preferred system plan and do we have an opportunity to review those?

1:14:37  
Yes, we published the ELCC in the both in the documentation.

1:14:41  
We also publish the input workbook that the inputs we use for the integrated calculation is a workbook also published in box.

1:14:51  
So you can check out both.

1:14:53  
And then to answer your question, yes, the ELCC is aligned with the PSP portfolio.

1:14:59  
We actually directly, yeah, we took that from the PSP Resolve Resolve viewer.

1:15:09  
So yes, you will be able to check out both and I think you will have opportunities to comment on the draft model.

1:15:20  
Great.

1:15:20  
OK, question from Asan in the chat.

1:15:23  
I'm not sure if I understood this correctly.

1:15:24  
So if you include GHG revenue, the avoided net costs are negative?

1:15:33  
Yes, if you don't set a floor for the avoided cost.

1:15:39  
So for us, the floor of the GG wooded cost is said to be the same as a carbon trade.

1:15:46  
So the carbon trade allowance price under CARB’s Coventry program.

1:15:50  
And then the floor of the capacity wooded cost is said to be the existing, the O&M cost of maintaining existing gas plants.

1:16:01  
So with all these floors, the avoided cost could be lower.

1:16:18  
OK, so Desiree Wong has two-part question in the chat.

1:16:23  
I'm not going to read the whole first part.

1:16:25  
It's just summarizing what is said in the regulations.

1:16:30  
Part 2 is can you confirm that the 8 hour storage is only included in the integrated calculation for 20-30 and beyond and it is not used to set the avoided costs in the pre 20-30 time frame?

1:16:43  
That is correct.

1:16:45  
And the reason we did that was because the 8 hour storage was not the IRP result model didn't build substantial amount of eight hour storage until the 2035 time frame.

1:17:00  
So yes, before 2035 we were mainly included, we included four hour storage and then after 2035 we included eight hour storage.

1:17:15  
OK, great.

1:17:16  
Let's go ahead and go to raised hands.

1:17:18  
Let's start with Tom, go ahead and it yourself.

1:17:25  
Yes, thank you Tom Beach for Sia.

1:17:29  
So I my question is about the fact that that the integrated calculation is only looking at two resources, solar and storage.

1:17:41  
You know, the, my, my understanding of the intent of this methodology and I think it's, it's, it's summarized in your point #2 down here, multiple resources provide multiple value streams.

1:17:53  
The, the intent of this I thought was to look at the all the resources selected in the IRP portfolio and, use this calculation not just on 2A limited set of two resources, but on everything.

1:18:12  
And if, and you know, I think a lot of the parties in the update proceeding recommended that, you know, we have further process here to look at the results of the integrated calculation when it's applied to the full IRP portfolio.

1:18:31  
I'll tell you that we've looked at the integrated calculation model and have run it on various combinations of we haven't run it on a full IRP portfolio, but we've run it on geothermal and storage instead of solar and storage.

1:18:46  
We've run it on solar and geothermal and storage.

1:18:50  
You know, three resources and you get different answers every time.

1:18:55  
It seems to us that you're probably going to get higher avoided costs the more resources you include because you're, you're going to have more constraints on being able to fully recover the cost of all of the resources that are in, in the IRP portfolio.

1:19:13  
And it, it, it seems to me that just picking solar and storage, there's, there's no indication that these are really the marginal resources in every year of the IRP portfolio.

1:19:26  
And in fact, they're certainly going to be years where there are some quite expensive resources like offshore wind that may be the marginal resource in the IRP portfolio.

1:19:38  
So how do we have confidence that these values are accurate?

1:19:56  
Thank you for that comment, Tom.

1:19:59  
I will say as we starting with this new model, keep it simple, really allowed us to better understand and interpret the model outputs.

1:20:10  
And I hear your point of not including wind for this iteration.

1:20:16  
I will say the main reason of doing that is because defining a generic wind resource is pretty technical challenging because wind generation profiles as you may know and cost really very drastic.

1:20:29  
Basically by different locations, whereas solar and storage as much more homogeneous and don't vary vary little by location.

1:20:40  
And therefore it is more straightforward to us for us to include kind of a generic solar and a generic storage in this model.

1:20:54  
Regarding the, the impact of including geothermal, our the approach we took was if the resource was selected because of the mid term reliability order, we assume that this resource is not avoidable by the DER and therefore we didn't include that in the integrated calculation.

1:21:22  
But there's geothermal in the IRP portfolio that goes well out past midterm reliability.

1:21:31  
And again, there's no, how do you know that wind isn't on the margin a more expensive resource than solar?

1:21:41  
I, I appreciate that, you know, there may be different wind profiles for different regions, but my question is, is, is whether this whole calculation is, is coming up with values that are significantly too low because you're not looking at the marginal resource for the IRP portfolio.

1:22:08  
Can you all, can you all hear me?

1:22:13  
Yes, yes, Nick.

1:22:15  
OK, great.

1:22:15  
I, I think I just got elevated to panelists.

1:22:18  
This is Nick Schlag with E3.

1:22:20  
Wanted to provide a little bit more background on kind of the logic and rationale for focusing on solar and storage in addition to what functioning said.

1:22:28  
And I think we tried to articulate some of this in the documentation, Tom.

1:22:32  
So hopefully if my answer doesn't quite do it justice, our, our, our text around this can help as well.

1:22:41  
I think there are a couple pieces of information that we have that do it provide a pretty good indication to us that energy storage and solar are sort of consistently quote on the margin as far as resources selected on the basis of economics throughout the IRP planning horizon.

1:22:59  
And that's the fact that generally speaking, across most of the years between 2024 and 2045, we see that in the Resolve preferred system plan, the model chooses to select some additional solar and some additional storage again in most of those years in order to meet constraints related to greenhouse gases and reliability.

1:23:20  
So that's one piece of information that we have that I think gives us an indication that those two resources are fairly consistently on the margin.

1:23:29  
I think Function's clarification was a good one that, you know, there are certain resources that end up in the portfolio, not necessarily because they were selected on the basis of their abilities to contribute to these two constraints, greenhouse gases and, and reliability.

1:23:46  
But instead because of a variety of other constraints, in particular near term requirements around the midterm reliability procurement orders and also the LSE plans, which were also forced into the preferred system plan and, and didn't kind of allow resolve to, to make an assessment of whether those resources would be economic on the basis of the assumptions used within the IRP proceeding.

1:24:13  
And then one more comment on this, you know, the, the concept that's being applied here is, you know, within economics kind of known as applying an addition to, you know, a long term portfolio.

1:24:27  
And economic theory would generally state that under equilibrium, in fact, there is no single resource that's on the margin.

1:24:36  
There's no single resource that kind of sets the price for everything.

1:24:40  
Every resource within that portfolio has been adjusted up or down up to the point at which it's feasible that it's value is aligned with its cost.

1:24:50  
And so that's why it gives us some comfort to, to focus on two resources that we know we can characterize really well and really consistently across the planning horizon.

1:25:00  
Because theory would tell us that, you know, the GHG price that we're willing to pay to a solar resource in terms of avoided costs should be equal to the GHG price we're willing to pay to any other resource in the system.

1:25:13  
And if it, if for some reason that weren't true, that would imply that we've done too much of one thing and too little of another.

1:25:20  
And there should be a, a different equilibrium that we could have found.

1:25:29  
You know, I, I, I think that, that the, the problem is, is that if, you know, if there are resources in the plan that are, are being procured for, as you said, some kind of other reasons than than GHG and capacity, presumably those other that maybe it's something called resource diversity or something like that.

1:25:59  
Those other considerations have value and, and that value needs to be, you know, picked up somewhere.

1:26:09  
And so, you know, I, I think there's going to be a lot of skepticism about whether whether this approach is, is providing an accurate value until you've looked at the entire, in the entire IRP portfolio or until you've shown that your presumption that this is some kind of equilibrium and that the marginal value of solar is the same as the marginal value of every other kind of resource that's in the plan.

1:26:40  
I mean, I, I would, would really challenge you to to put offshore wind in here and, and see what, what results you get.

1:26:51  
Yeah.

1:26:51  
Thank you.

1:26:52  
Thank you for your comment, Tom.

1:26:53  
I think at this point we're going to move on to other folks who have their hands raised.

1:26:59  
Thanks.

1:26:59  
All right.

1:27:00  
Let's go to Eric now.

1:27:03  
He should be able to unmute yourself.

1:27:06  
Can you hear me?

1:27:20  
Yes, I can.

1:27:21  
This is Eric Borden with Synapse Energy Economics.

1:27:24  
We're working with NRDC in this proceeding.

1:27:27  
I think I have two questions, probably much simpler than the last one.

1:27:32  
Could you go back to that slide with the formula?

1:27:35  
Yeah, this one.

1:27:36  
So for the capacity value in greenhouse gas value, do you just scale those up or down based on like whatever their proportion is to each other?

1:27:49  
Because like obviously when you do the calculation, they may not exactly equal the resource cost.

1:27:55  
So how do you proportion them the capacity value in greenhouse gas value to to equal the resource cost?

1:28:07  
Oh, I see.

1:28:08  
So for our purpose of the modelling, we calculate everything for one MW of installed resource.

1:28:16  
So everything is in terms of like per kilowatt or yeah, per kilowatt year basis.

1:28:25  
Does that help or So I'm asking like, so when you do this calculation, energy plus capacity plus greenhouse gas, you're probably not going to get something exactly equal to resource.

1:28:37  
Oh, I see.

1:28:38  
Right.

1:28:39  
Yeah, yeah, got it.

1:28:40  
Got it.

1:28:40  
Do you just scale?

1:28:41  
Yeah.

1:28:41  
How do you scale the different?

1:28:43  
Yeah, No, that's a good question.

1:28:44  
So this is definitely a simplification of how we actually implemented in in in terms of like the actual implementation, we represented this equation as an optimization model.

1:28:59  
So we first represent the basic equation as an inequality.

1:29:03  
So the value has to be equal or bigger than the cost.

1:29:08  
That will be the main constraint of our optimization.

1:29:11  
And then we all this, we also designed this as a kind of cost minimization problem.

1:29:16  
So we're minimizing the total value and the total value for each resource.

1:29:23  
So yeah, exactly like we basically use this optimization to try to achieve this equation to be to let both sides of the equation to be as close as possible.

1:29:37  
OK, I think I mostly get it.

1:29:39  
Thank you.

1:29:40  
And then my other question is how do you allocate the values across time in the ACC?

1:29:49  
Do you?

1:29:50  
Is there a different allocation methodology for these three values that you see here?

1:29:56  
Are they all lumped together and and then allocated in the same way, Right.

1:30:01  
They have different allocations.

1:30:03  
So the energy, what it costs are straight that comes directly from the server modelling.

1:30:10  
So it, it will be hourly voided cost that we are receiving for the capacity value, we allocate that to the hours where there's highest probability of loss of load events.

1:30:24  
And then SERVM will actually the SERVM team will talk about how we allocate the capacity, what it costs, costs in the next section.

1:30:32  
And then in terms of the allocating GHG of what it costs, we all equip them based on the system marginal emission rates and that's derived using energy prices and the implied heat rates of also from energy prices.

1:30:50  
So yeah, they are allocated in a different ways.

1:30:53  
Yeah, interesting.

1:30:54  
Thank you.

1:31:02  
OK.

1:31:03  
I don't see any additional hands raised in the chat or additional questions.

1:31:08  
Oh, OK.

1:31:10  
One more from Tom.

1:31:12  
Although I will say, Tom, we have to stay on schedule here, so give you one more shot at it.

1:31:20  
Sorry, I think I just accidentally lowered your hand.

1:31:23  
Tom, let me find you again.

1:31:25  
There we go.

1:31:26  
You should be able to speak.

1:31:29  
Yes, thank you.

1:31:30  
I just have a quick follow up on that, that last question which was a good one.

1:31:35  
So you know, we we've looked at whether so, so you pointed out that the next section of this presentation is going to be on how capacity value is allocated across the hours.

1:31:53  
Have you checked to see whether because because that uses an an entirely different set of, you know, like EUE and and data from SERVM.

1:32:02  
Have you checked to see whether when you use that allocation across the hours, whether solar still is able to recover its costs?

1:32:15  
It it appears to me that that solar may under under recover its costs when you consider how you've allocated the capacity value across the hours of the day.

1:32:40  
We have checked the ELCC against the capacity allocation factors.

1:32:47  
I don't have the result ahead of me, but I think our conclusion or mean take away was they are aligned in terms of evaluating solar.

1:32:59  
Can you provide that information because that would be a useful check on the overall, you know, ACCI think all the information we have, I think stakeholders would have all the information they need to also do this calculation.

1:33:24  
But well, let's let me go back and see if we can provide that, because we also publish the capacity allocation factors and then we also publish the ELCC for the resources.

1:33:39  
But you, it sounds like you appreciate that, that your capacity allocation factors need to be consistent with your Elccs.

1:33:47  
Yeah, we, we agree with that.

1:33:49  
The capacity allocation factors should be consistent.

1:33:54  
Thank you.

1:34:05  
OK.

1:34:06  
I think we're coming right up on schedule for a break for about 10 minutes before we go to the next section.

1:34:17  
So if we want to take that break now and then re convene at 2:50 PM to continue this discussion.

1:34:31  
Thanks everyone.

1:46:11  
Hi, everyone.

1:46:11  
It's 250.

1:46:14  
So Alex, I don't know if we want to start back up again.

1:46:20  
I believe on the agendas when we're supposed to start back up again.

1:46:24  
OK, great.

1:46:25  
Yeah.

1:46:25  
So Donald and Munir, I believe this sections for you all to present.

1:46:33  
Yeah, I'm going to ask Kevin Carden to present the next section of the slides.

1:46:43  
Thanks, Donald.

1:46:44  
Kevin Carden here with us Tropic Consulting or Power Gym Company, we are the vendor for the SERVM model.

1:46:51  
I'm going to explain some of the new dispatch methodology that we implemented in SERVM that influences how the capacity value gets spread differently from prior implementations.

1:47:04  
Go ahead and jump to the next line.

1:47:11  
So just thinking about actual operations of the system, how do we operate batteries in a case where we know that we're going to have a shortfall, So on a day, really high, peak low.

1:47:21  
This is just a generic example of 100 GW system where we only have enough conventional resources to meet 72,000 megawatts of load.

1:47:30  
Beyond that, we're going to have to dispatch other resources.

1:47:33  
We have two options.

1:47:34  
We can either use all the storage that we have as available until it's exhausted.

1:47:42  
Once it's exhausted, we're just going to have lots and lots of unserved energy.

1:47:46  
Or we can optimize the storage schedule and use it to shave the net load peak.

1:47:52  
When we do that, we'll essentially have equal expected unserved energy across that entire dispatch window.

1:47:58  
So two different dispatch methodologies.

1:48:01  
The 1st is how it has historically been operated in serving, we're mimicking the way that we would expect operations to work.

1:48:08  
You just don't have perfect visibility into what will happen in the future.

1:48:11  
So if I have enough resources, I will dispatch them to meet the load and just run until I exhaust the resource.

1:48:19  
What that does though is it doesn't recognize an accurate, it doesn't provide an accurate reflection of the time of the temporal value of of energy because this storage exhaustion is driving the event.

1:48:35  
We recognize that there is a fungibility to the energy across this entire dispatch window.

1:48:41  
If I get one extra MW hour of energy, any point between 4:50 in the afternoon or 5:00 in the afternoon until midnight, any of that energy will directly offset unserved energy will reduce the amount of unserved energy we have in this day for any energy that's produced across this entire window.

1:49:01  
So in order to capture that we are departing from the way you might operate the system, but this will this modeling approach will give us an accurate reflection of the value of energy across the entire dispatch window.

1:49:16  
So on a day that we have unserved energy, a day that we have this shortfall, we exhaust the storage, we take the dispatch of the storage and we spread it out across an entire window.

1:49:30  
And then you have equal unserved energy across this entire window.

1:49:33  
And then we when we measure the reliability, it's spread out more to reflect kind of fungibility of energy across that entire dispatch window as illustrated a little bit further on the next slide.

1:49:49  
So on a, this is just a snapshot day, we had significant unserved energy really late in the day and hours 23 and 24.

1:49:58  
Again that was driven by energy exhaustion of the batteries.

1:50:02  
So we had fully used all of the state of charge in the batteries.

1:50:06  
Once we had exhausted it, load, net load now is higher than our resource availability.

1:50:13  
So we shed load.

1:50:15  
So on that day we take that unserved energy and we redispatch the storage.

1:50:22  
So it's a counterfactual storage dispatch where we spread it out so that we have equal unserved energy across the windows so that now we can capture if I produce one additional MW hour of energy and hour 17 and I will directly reduce unserved energy or 1819 anytime during that entire dispatch window.

1:50:47  
So this better aligns with the actual contribution to reliability than the method before.

1:50:55  
In terms of the temporal alignment of kind of the value of of energy.

1:51:03  
If you go to the next slide, see that the total expectedness of energy for each of the months matches up, but it's more spread out in the new storage dispatch using the new storage dispatch logic.

1:51:19  
There are a few nuances today as I won't dwell, I spent a lot of time trying to elucidate some of that.

1:51:26  
But essentially this energy equity we recognize in the in the later years especially a lot of the shortfalls are due to energy exhaustion.

1:51:36  
And that energy exhaustion when we implement this methodology, it spreads out that unserved energy, we do have some capacity shortfall events.

1:51:46  
If you look at the September profile of unserved energy, an hour 18 sun goes down a little bit earlier and we are, we haven't exhausted the storage yet, but we still have a shortfall to be a capacity shortfall.

1:52:00  
And later in the day, you see more of the energy exhaustion events driving the reliability.

1:52:05  
So not as clean in terms of the spreading of the unserved energy in September is what you see in in August.

1:52:14  
And again, this is a composite of lots of days of unserved energy.

1:52:17  
So some days you may have capacity shortfalls, some days you may have energy shortfalls, obviously not the same amount of shortfalls on each day.

1:52:25  
So the reason for the profile of the unserved energy there, but we feel I'm confident this is a methodology change that we are exploring in lots of different venues across the country to better recognize the value of of all resources and their contribution to reliability.

1:52:44  
I think that's the last slide that I have take questions there.

1:52:57  
We have one from Haley.

1:52:58  
I'll go ahead and unmute you, Haley.

1:53:00  
So you should be able to, this should be a pretty easy one and sorry if I missed it.

1:53:07  
What does EUE stand for expected unserved energy.

1:53:12  
Thank you.

1:53:12  
It's the MW hours difference between our load and ancillary service obligations and the resources that we have available.

1:53:34  
OK.

1:53:35  
I don't see any other hands raised.

1:53:38  
Can give folks a minute.

1:53:40  
We did set aside some time for discussion here.

1:53:43  
So if there's anything else, Damon, go ahead.

1:53:51  
I mean, in the in the 2022 ACC, it seemed like if I understand the numbers correctly, the most of the answer of energy was in September.

1:54:01  
And it looks like that sort of shifts to August.

1:54:05  
And the new model is that is there a reason behind that?

1:54:08  
And is that kind of the correct assumption?

1:54:12  
Donald, this one may be one for you to respond to.

1:54:14  
I'm not sure which year this table came from.

1:54:19  
Certainly over time it changes.

1:54:22  
Yeah, 20, 30.

1:54:27  
The change in the hyper probably motivated some of that.

1:54:34  
Also, I think between the last ACC and this ACC, we may have added, yeah, the weather year 2019 and 2020 weather year, we're not quite in this ACC.

1:54:47  
We're we're using the old PSC.

1:54:49  
So we're not up to 2022 yet, but I think we added 2019 and 2020 weather years.

1:54:54  
20/20 was pretty bad in August.

1:54:57  
Yeah.

1:54:59  
So no other questions for me.

1:55:29  
I am not seeing any.

1:55:40  
OK, great.

1:55:41  
So we can move on to the next section, Andrew Soulfest from E3 if you want to take over, everybody able to hear me fine.

1:55:55  
Yes, great.

1:55:58  
Thank you.

1:55:59  
So my name is Andrew Sulfest.

1:56:00  
I'll be walking through the transmission and distribution of wedding costs, giving a refresh around the methodology for each of these and then highlighting the updated results for the 2024 cycle.

1:56:11  
We'll ask just to again, same as the prior sections, just please hold the questions, tell us through both the transmission and the distribution sections and then we can certainly jump back to individual slides as needed.

1:56:25  
Mind changing the next slide, please?

1:56:28  
Thanks.

1:56:30  
So both the transmission and distribution cost avoided cost methodologies remain generally unchanged from the 2020 to ACC.

1:56:37  
So I apologize, I don't have anything quite as exciting as the integrated calculation to show you, but the transmission avoided costs in particular rely heavily on utility general rate case or GRC filings with some supplemental transmission planning and cost factor data obtained from the utilities as well as I think the, I apologize, I forget who the question had come from before, but also some of the load data from the CAISOEMS data set as well as load forecasts from Hyper.

1:57:10  
But for the PG&E, it basically stops there since in the most recent GRC approved, I should say, their final value was set by the Commission and that remains in place.

1:57:23  
For both SCE and SDG and E, we actually use two different approaches in combination, the discounted total investment method or DTM and a locational net benefits analysis or LNBA method.

1:57:38  
So I'll walk through these at a very high level on the next slide and then address the final results.

1:57:43  
And then the last piece on this table is just to allocate the avoided cost values over time.

1:57:49  
We use peak capacity allocation factors or P caps, which I'll touch on after we go through both the transmission and distribution section, since similar method is applied to both.

1:58:00  
Move to the next slide please.

1:58:02  
Thanks.

1:58:04  
So while the particulars differ, the broad goal and approach of both the D SIM and the LNBA method is to take the total cost of plan investments in the transmission system to address capacity needs and divide it by the forecast of load growth that those projects are expected to address.

1:58:21  
Then you end up with the unit cost value.

1:58:23  
The DTIM approach, which is kind of shown in very summary steps at the right side of this slide focuses on projects designated as addressing system wide needs.

1:58:34  
The LMBA method is pretty similar at least in the broad goals, but it is focused specifically on individual large projects that are concentrated on the subsection of the system.

1:58:46  
As such that the cost for those individual projects are scaled for the portion of the system load that they're actually addressing.

1:58:54  
Under both methods, you annualize the values to go from a present dollar present value, dollar per kilowatt number to a dollar per kilowatt year value and add in additional cost factors such as admin and general expenses and then O&M.

1:59:10  
For SCE, which actually takes results from using both the DTM and the LMBA approach and combines them, you add O&M in the end.

1:59:19  
You can see that at the bottom on the right side of the slide, whereas for SDG and E, everything is captured just using the DTM approach alone.

1:59:30  
If you'd like additional detail on the calculations for both of these utilities, definitely encourage you to check out Appendix Section 12 of this cycle's documentation.

1:59:39  
Then we have the more detailed full set of calculations laid out there.

1:59:44  
You can see both the load numbers and the investments going in.

1:59:47  
And then of course, as I mentioned on the last slide, PG&E doesn't actually have this approach applied during this for an ACC cycle since their transmission value was already set by a prior ruling and remains in place.

2:00:00  
Next slide, please.

2:00:03  
Thank you.

2:00:04  
So looking at the results of the transmission calculations for the 2024 cycle, an important piece of the story is that they remind us that transmission cost can be lumpy.

2:00:15  
Get to what that means in a moment.

2:00:17  
So SC, ES transmission value in this case increased by about a third.

2:00:22  
Well, SDG and ES decreased pretty drastically as you can see on the graph by about 75%, all well following the same methodology as the prior cycles and simply based on updates, what transmission investments are taking place right now and what the expected load growth looks like.

2:00:38  
So this gets into the lumpiness.

2:00:39  
When we talk about the lumpiness of transmission investments, it refers to the fact that transmission investments can both be very large investments and they have long useful lights, but those investments aren't necessarily evenly spread out over time.

2:00:54  
So to give a great example of that, the drop in cost for SDG and E was actually something that was expected and foreshadowed in this last workshop two years ago for the 2022 ACC cycle.

2:01:06  
So at that time, there was a drastic increase in costs and SDG and E had noted this was due to an unusually high number of transmission investments planned to take place in the short run, in part because the recent focus had been devoted to all their needs and their capital kind of expenditures, including wildfire mitigation and other items.

2:01:28  
And then at that point, it was now considered really time to address all those transmission needs that had piled up.

2:01:33  
So they had a lot of additional transmission planning in a short period of time.

2:01:39  
But now that we've moved part of the way past that particular lump, the total investment dollars and costs now that are in the future of forecast period have dropped most of the way back down towards what they were in 2021.

2:01:52  
They're not quite all the way there.

2:01:54  
And as you can see, they align a lot more closely now again with what we're seeing for the other two utilities.

2:02:00  
One minor improvement we've been able to make for the 2024 cycle to help address the different aspects of this lumpiness is that we've extended or expanded the hyper forecast used under the detailed method to go through 2040.

2:02:14  
So this isn't a change in methodology or new concept and tactic, but it's just simply that there's more data available or a longer forecast that we're able to actually get a few extra years in there basically.

2:02:26  
And it's really important to note that by using that forecast, it's not spreading the costs across more years.

2:02:34  
Instead, because we only have project costs for a handful of years into the future, 5 for SCEI believe and six for SDG and E, we aren't spreading out that cost all the way through now and those six years of cost from now all the way to 2040.

2:02:49  
Instead, what we're doing is taking the median load growth between now and 2040 across that longer horizon and applying it to each year of investment.

2:02:59  
So it's still comparing the same number of costs with the same or same number of cost years with the same years of load growth.

2:03:06  
It's just taking the median instead of looking at the individual years 1 by 1.

2:03:11  
And so as I mentioned, this median approach isn't brand new.

2:03:14  
It's something we did rely on in the past couple cycles as well.

2:03:17  
But now just thanks to the longer horizon available to us, we're able to use that while still being within a reasonable useful life for many of these projects.

2:03:26  
So it's within what's being considered enough planning.

2:03:30  
So the reason to use that median from a longer period is that it helps reflect the fact that investments made today or this year aren't intended to address only the load growth that's happening right this second.

2:03:41  
They're based on expected load growth across a longer period.

2:03:45  
So even if system load might be decreasing in this year or next, which does happen sometimes in individual years and would give you a negative transmission avoided cost, the investments made today are actually to prepare for low gross say a few years down the line.

2:03:59  
Using the median approach helps to reflect this appropriately.

2:04:04  
So moving on to the transmission methodology or distribution, sorry, thank you.

2:04:12  
So on the distribution of what it costs, we've continued to use the methodology described in the 2019 distribution white paper.

2:04:20  
I apologize it says T&B, but it's really distribution white paper there updating with new inputs from the utility GNA or grid needs assessment and DDOR or distribution deferral opportunities reports.

2:04:34  
So following this white paper method, we look at the difference between counterfactual and forecasted distribution system overloads to determine what otherwise needed upgrades DERs are able to help and avoid or defer at least.

2:04:48  
So one necessary refinement we have made I do want to call out in this in the near term calculations is to calculate value separately for individual facilities that are experiencing a net increase in load due to DERs versus facilities increase experiencing a net decrease in load due to DERs.

2:05:07  
We are still following all the same steps from the white paper and we still end up with a single distribution value.

2:05:12  
We had to basically separate out or or duplicate the intermediate steps in order to respond to and reduce sensitivity some of the to some of the differences or changes we've seen in the newer more recent DER forecasts.

2:05:26  
More specifically, we want to prevent the possibility of generating an inappropriate negative DER value which would actually results or negative avoiding cost from this year's data if we didn't apply this adjustment.

2:05:40  
So I'll talk through this in a couple slides, but coming back to this slide first before we move on, similar to the transmission methodology slide I showed the table at the bottom here list the data sources used for the general approach are used and the general approach.

2:05:56  
So as you can see, the GRC filings feature pretty prominently once again as our source, particularly for the long term marginal distribution costs.

2:06:05  
So on the distribution side, we calculate things for the near term and then for the long term values, those are actually taken directly from the filings, our utility filings and they give more of a top down perspective, whereas the near term is is bottom up.

2:06:21  
So can you go to the next slide please?

2:06:25  
Thank you.

2:06:26  
So to give some additional context, I want to talk through the white paper methodology which has been in place since the 20/20/2020 sorry ACC update.

2:06:36  
So this white paper I keep referring to was put together by the Energy division and back in 2019 as a proposal to better make use of available distribution data and near term distribution planning and determine what specific investments might actually be avoidable by DERs or deferrable and assign a value to them.

2:06:56  
So after some discussion with the stakeholder parties at that time it was adopted for use in the subsequent AC CS.

2:07:03  
So we use those near term distribution costs following this methodology for the first few or the near term years of the forecast.

2:07:11  
And then in the later period in the forecast, we use the kind of top down long term numbers that we're getting from the GRC filings.

2:07:21  
So this methodology is going to get a little bit in the nitty gritty already, but I do want to keep things at least relatively high level.

2:07:28  
So I'm going to just talk through the basic steps of the methodology before showing the summary calculation.

2:07:34  
But the purpose broadly of the white pepper methodology, as I said, is to go from the bottom up or facility by facility and determine what distribution capacity constraints are avoidable or expected to be deferrable by DERs.

2:07:48  
So to figure this out, we compare distribution system forecasts and expected overloads with a theoretical counterfactual scenario where DERs won't or wouldn't be built on the system.

2:08:01  
We look at what distribution theaters and substations are capacity constrained and what in the forecast would be overloaded and require upgrades within it.

2:08:10  
Then we take all those DERs out for the counterfactual and calculate those numbers again and again, see what capacity constraints are and what overloads and required upgrades are needed.

2:08:21  
So a keys key step from the white paper I mentioned that we're applying in the cycle is then to take the difference between the counterfactual and forecasted overloads.

2:08:30  
This is important in order to make sure we're determining what incremental overload capacity is actually being deferred by the DERs instead of all planned investments plus DERs.

2:08:41  
So we multiply that resulting difference in overload capacity by the unit cost of upgrades to determine how much additional investment is being deferred by DERS.

2:08:51  
And then we divide that number and by the forecasted Dr.

2:08:56  
capacity, get the dollar per kilowatt and annualize it to again get into a dollar per kilowatt year, that familiar unit and add in the additional cost factors in the process to end up with again that dollar per kilowatt year final value.

2:09:13  
Do you mind changing the next slide?

2:09:15  
Yeah, perfect.

2:09:16  
So again, same slide basically, but showing the summary calculate calculations as well just for PG&E.

2:09:23  
And this is included in the documentation for all the utilities, so you can look at it there in more detail.

2:09:30  
I apologize, it's probably hard to read any of the individual values here, but those aren't really what I want to highlight.

2:09:36  
Instead, I want to focus on the green box, which is the change I mentioned earlier to split calculations based on whether a feeder experiences a load increase or load decrease due to DERs.

2:09:47  
So the reason we're pursuing this, this adjustment to split the load from load increasing and load decreasing fears is necessary for two reasons.

2:09:59  
First, the DERs that increase peak load such as EVs or heating electrification will contribute to an increase in overloads on the system.

2:10:08  
If you take those DERs out of the equation in the counterfactual, the number of overloads drops.

2:10:13  
So you're actually when you take the counterfactual minus actual, you're actually reducing the investment required and you end up with negative numbers.

2:10:21  
You can see on the right hand column here.

2:10:24  
And if you're going feeder by feeder, normally this might be fine as long as you have negative divided by negative in a later step.

2:10:30  
But if you're going feeder by feeder and say that the net load impact of the E Rs on some feeders is positive and on some other feeders is negative, but then you blend all those together.

2:10:40  
When you take the step to divide, divide by the capacity of forecast of the ER, those signs might not match up and you can end up with a negative marginal cost result.

2:10:50  
So that's what was occurring when we were following the prior methodology using the updated numbers.

2:10:54  
This is basically because there's more electrification on the system and on an individual kind of feeder by feeder basis, it doesn't always line up perfectly, which makes sense.

2:11:04  
And in a real world application, the second reason the split's necessary is really tied to the first.

2:11:10  
Even if you don't end up with a negative result, if you have some facilities with load increasing the E Rs, that effectively cancel out the impacts of load reducing the E Rs.

2:11:19  
And those numbers are approximately equal.

2:11:21  
Because I mentioned we divide by the capacity of DERS on the system.

2:11:25  
If you're taking a net number and those are close to equal, you get really close to 0.

2:11:31  
If you divide by a number approaching 0, the result approaches Infinity, which doesn't actually accurately reflect the impact of those DERS on the system.

2:11:40  
And just like getting a negative result, it's ultimately a sign that we're conflating the impacts between those two different types of DERS.

2:11:46  
And you have kind of this fight between the negative and the positive impacts.

2:11:50  
That's where you're getting just, it's harder to explain results that really aren't applicable.

2:11:57  
By separating this out with the update we've made, we're able to follow the original white paper methodology still just doing it basically in two separate lines and then reliably obtain an appropriate avoided cost value.

2:12:11  
You mean moving to the next slide again?

2:12:15  
Thanks.

2:12:16  
So having refreshed all that methodology, what are the actual results we're seeing for the 2024 ACC?

2:12:24  
So thanks to the adjustment, the near term costs are no longer negative, but they have dropped significantly from the 22 cycle.

2:12:33  
This is partially due to the difference taken between the counterfactuals and actuals with the values.

2:12:39  
With the adjustment, the values for all three utilities are now all on the same order of magnitude Rather than having PG&E and SC ES per unit cost being so much higher than SDG and ES.

2:12:51  
However, the longer term cost values which I mentioned are top down and have been consistently much higher than the near term values that's expected.

2:12:59  
Those have also not changed since the last update because these long term costs are applied to a broader range of years and they have a larger impact on the levelized cost.

2:13:09  
And as or if you might recall from functioning slides way at the beginning, and I think you'll be able to see very shortly in the societal cost test slides coming up after this, those levelized distribution values haven't actually changed nearly as much because of that waiting.

2:13:27  
You can see just to to give a snippet that the red box, the bottom graph just highlights the near term values and then you can see over to the right on that graph how they scale up over a couple of years.

2:13:37  
We have this two year transition period to get to the long term values which are applied to the rest of the horizon.

2:13:43  
Ultimately that's used just to have kind of a happy medium in between the two approaches and to include both the near term additional information that we have from the distribution planning and some of the long term planning or expectations for those those higher values.

2:14:02  
So think just one more slide here, you don't mind moving to the next.

2:14:06  
Thanks.

2:14:08  
So before we get to keep some Q&A and then the societal cost us results, I do want to just cover the last piece of the puzzle for both transmission and distribution, which is the P capacity allocation factor and support P caps.

2:14:23  
Thankfully, the P caps or for the P caps, the inputs and the methodology are much more straightforward and really just simply rely on recent load patterns.

2:14:33  
So to generate P caps, we take the top hours of load in each service area and assign factors assigning the OR according to how much of that load is concentrated in each.

2:14:44  
Basically those factors all need to add up to 1 so that if you multiply them all together, you'll end up with the original distribution or transmission cost.

2:14:53  
But ultimately you do multiply those those factors by the total transmission and distribution values so that D Rs are compensated based on their ability to address capacity needs in each of these key peak hours.

2:15:06  
So the results really for this year, which I think are more of the focus.

2:15:10  
As you can see from the charts, allocation factors haven't changed all that much from the 2022.

2:15:15  
ACC for the transmission load has gotten very slightly peakier but is largely unchanged and the peaks are still concentrated in the late afternoon and early evening for distribution.

2:15:28  
These factors actually are updated for PG&E and SCE within the cadence of the GRC filings.

2:15:34  
They haven't changed at all since 2022.

2:15:37  
SDG and ES values have shifted slightly in this particular climate zone makes it more evident.

2:15:44  
But this again is just tied to the load patterns in each climate zone.

2:15:47  
Individual climate zones like the one shown here can be a little bit more volatile where they have relatively fewer customers.

2:15:53  
And so any change the larger impact.

2:15:56  
Ultimately all of this is just a straight pass through effect of the load and the peak.

2:16:03  
So I think before we pass it back to talk through the societal cost test methodology, we should have time for at least a few questions on both the transmission and distribution side.

2:16:14  
Yeah, let's start with the chat from Tom.

2:16:21  
We have Tom Beach, we have what the ER forecast is used for the near term avoided distribution cost method and how are forecasted DER allocated to particular distribution circuits and substations.

2:16:37  
So the as far as the latter part of the question to make sure I'm understanding correctly.

2:16:42  
So what we provide is actually a unspecified cost and that's that's a big focus in the white paper methodology with the distribution, the near term distribution values.

2:16:53  
So those costs are applied across theaters and substations, though the like input data is basically the avoided cost from individual facilities.

2:17:06  
So we take that all and build it up kind of taking that bottom up approach.

2:17:11  
But then ultimately we take the average of all those marginal costs so that it is applied across the system.

2:17:17  
Ultimately this gives us a single value which can be varied by our or the climate zone when we do this P caps approach, but that it is still kind of a system wide initial value that we get to.

2:17:34  
As far as the first part of your question, was this description of the P caps approach enough to address that or were you looking for more clarification?

2:17:53  
Tom, feel free to raise your hand and I can unmute you if you need additional clarification.

2:17:57  
OK.

2:18:03  
So I mean I understand the peak half method, but the denominator of the avoided distribution cost is a forecast of der kilowatts, right?

2:18:15  
And so I'm wondering where, where do you get that forecast from?

2:18:20  
Yeah, in the right hand corner there.

2:18:22  
This is divided by the DER forecast kilowatts.

2:18:26  
Yes, yeah, OK, sorry.

2:18:27  
Thanks for clarifying.

2:18:28  
I thought you were referring to talking about the forecast for the P cast or the load data actually.

2:18:34  
Yeah.

2:18:34  
So on the distribution side, this is based on DER forecast from the utility DNA and DD or filings.

2:18:42  
I I am blanking on the individual tab of those filings right now.

2:18:49  
It isn't the documentation, but otherwise if you want to follow up later, I can can get back to you on that.

2:18:57  
Are those forecasts consistent with the hyper forecast of DER I their facility by or their sorry, their utility by utility?

2:19:09  
And then I I guess they should be generally consistent.

2:19:17  
I'm not sure exactly how they compare off hand.

2:19:19  
And we do use the hyper forecast and the transmission side and that's where we focused on it more on the distribution side.

2:19:26  
It's based on those those filings by the utilities.

2:19:31  
And and on my second question, in in order to know whether DER will alleviate a, you know, an, an over an overload on a, on a feeder, you have to somehow forecast how much DER would be developed on that feeder, right.

2:19:54  
So you have to take your, don't you have to take your forecast of DER and make assumptions how that's distributed across the system?

2:20:03  
Yes, yeah.

2:20:04  
So in, in the, the DDR reports there it is on a facility by facility basis of the forecast.

2:20:14  
Is that based on historical data on how much DER have have been cited on that feeder or is it just kind of peanut buttered across the whole system?

2:20:26  
I believe it's you're just going to jump in.

2:20:29  
This is analysis performed by the utilities that we receive in the GNA and DD or filing.

2:20:35  
So we don't have any insights as to how it's done beyond what they described in their documentation.

2:20:42  
I, I will say it's, it's not peanut butter to cross based on the discussions we've had with utilities.

2:20:47  
But yeah, they would be, they would be the best parties to, to answer those questions.

2:20:50  
And we use the 2023 DNA indeed or reports if you want to look through those and have have that discussion with them.

2:21:00  
Thanks, Eric.

2:21:09  
OK.

2:21:10  
Maybe it makes sense to go to Jan since it's on the same line of questioning Jan from San Diego, if you wanted to add a little bit of detail from the utility side should be able to unmute yourself quick couple of responses in to your question.

2:21:45  
The DERs are consistent with what DERs are forecast in the CECS i.e.

2:21:53  
PR that we use in that that particular year's distribution planning process.

2:21:58  
So there is a system level consistency for each utility.

2:22:03  
It is subject to known loads which tend to appear in the early years of the forecast horizon.

2:22:11  
We do accommodate all, all DER known loads.

2:22:14  
So that's one.

2:22:15  
Do you want to call it difference?

2:22:17  
But it, it, it does show up in the early years.

2:22:20  
And the other comment I was just going to make is the disaggregation method.

2:22:25  
You know, it's, it's a fairly sophisticated approach.

2:22:27  
We attempt to use a different kinds of data to determine how that i.e.

2:22:32  
PR system level forecast gets spread out to the individual circuits and substations.

2:22:37  
So it isn't just any kind of peanut butter spread.

2:22:39  
It's actually a more sophisticated approach based on particular DER technology and the data that we have access to.

2:22:47  
And there's a whole process we go through to try to improve that every year because as you can imagine that there's a lot of, you know, a lot of forecast inputs that go into that.

2:22:57  
Thank you.

2:22:59  
Thanks Stan, That's really helpful.

2:23:02  
Yeah, All right, let's keep moving.

2:23:05  
Eric, if you want to state your question, you should be able to.

2:23:11  
Yeah, thanks.

2:23:13  
I had to.

2:23:15  
Could you go back to the you had the short term versus the long term distribution marginal costs?

2:23:24  
Real quick, Eric, just for the record, can you do your name and organization?

2:23:27  
I apologize if you already have, just want to make sure it's on the record.

2:23:31  
Sure.

2:23:31  
Eric Borden, Synapse Energy Economics, we're working with NRDC.

2:23:37  
So does this.

2:23:38  
So this is, I mean, these are marginal costs.

2:23:42  
So does it make sense to you that there's such a vast difference like that the, you know, the marginal decrease in the near term is so much that that the value of that is so much different in the near term versus versus the long term?

2:24:01  
Like like does that make sense?

2:24:03  
I think speaking very broadly here or generically it, it is, is not unexpected.

2:24:11  
And this is pretty consistent for what we've seen here in the ACC and past cycles and in other jurisdictions as well, where the, the, the near term costs are a lot lower than the long term.

2:24:23  
Ultimately, part of it is due to the difference in approach here.

2:24:27  
So as I mentioned this is more of a bottom up approach.

2:24:29  
We're going kind of feeder by fill feeder, facility by facility and checking to see, OK, is this specific feeder going to have an overload or not.

2:24:41  
Whereas the kind of long term approach is more top down.

2:24:46  
I frankly can't speak so much to that because it what we use is pulled more directly from the utility filings, but it won't necessarily be as specific to it's it's broader distribution marginal costs whether whereas the white paper methodology that we use for the near term.

2:25:05  
So it's it's called and specified as marginal distribution.

2:25:09  
It is intended to be applied specifically for marginal distribution costs that applied to DERs or that could be avoided by DERs.

2:25:19  
They have to be capacity specific and it also has to be designated as DER eligible etcetera.

2:25:25  
That goes into I think a little bit more of the I guess granularity of it.

2:25:32  
But that all of that is to say, I think it is definitely a big gap and there's definitely room for improvement on on bringing these together broadly throughout the industry.

2:25:43  
But it is pretty consistent that these these near term costs that that you get from a bottom up approach and which won't necessarily factor in all of the same kind of additional expenses etcetera.

2:25:57  
And and long term planning is that the top down long term approach is consistently very low in comparison.

2:26:06  
And then the top down approach, we tend to think of it as really more of a high end because it's not going to be isolating for specific factors that would guarantee that this capacity is actually where this these upgrades are explicitly avoidable by having these DERs on the system, which is a long way of saying this is there's it's not frankly, it's it's not perfect.

2:26:30  
It's always a work in progress, but it is this is pretty, pretty standard to see this or a significant difference between the high and the low, right.

2:26:41  
Yeah, no, that's, that's helpful to remind me that they're two totally different methodologies And like maybe in the next whatever the two year next update, we could think about kind of marrying the methodologies together because like on a marginal basis, I just don't know that it makes sense to like have crazy fluctuation.

2:27:00  
OK.

2:27:00  
My other question probably quicker is for the transmission side.

2:27:05  
You mentioned do you isolate load gross projects?

2:27:08  
And so my understanding of transmission projects is that they're often for like multiple reasons.

2:27:13  
So like what's your, how do you think about whether a project is load growth or not?

2:27:20  
Is it just like it's one of the reasons and then it's load growth or is there a portioning or how do you, how do you do that part?

2:27:27  
I will say that's, that's not as much a decision we make is one that we, we ask the utilities for their data on the, the transmission projects that are applicable to include for this.

2:27:38  
So it's I, I apologize, I don't have a great answer for you on that.

2:27:43  
OK, thanks.

2:27:50  
OK, let's go to Brad.

2:27:52  
You should be able to on this slide given the vast difference in methodology, the great difference in methodology and the vast difference in results in the near term and the long term.

2:28:10  
It seems to me in in the use of the tool that it would be necessary to look at the levelized value for the life of the of the DER system.

2:28:23  
And to not do so is effectively ignoring looking at this chart, pretty much the entire value.

2:28:30  
If you only look at the at the first year, the first couple of years and the value that that produces you're, you're, you're not including the true value of that marginal DER.

2:28:43  
And so I mean, is that is that would you agree that it would be sort of a misuse of the tool to not levelize it over the life of the system?

2:28:50  
And and then sort of related question, maybe this gets at what Eric was just saying and wanting to sort of bring these together in the future.

2:28:56  
One way to just deal with that now is to not use single year values, but to always use levelized value in the use of the tool.

2:29:08  
I, I apologize, I I can't really speak to the use of the tool or advise on that.

2:29:14  
So specifically, I think that might be might be a, a broader question.

2:29:19  
I'm not sure if someone from the energy division or or else would like to weigh in there.

2:29:23  
This is Eric any three I can jump in the time and loads of the DER.

2:29:37  
So whether it's a three-year or 25 year in the case of solar, whether you levelize it or not, it's it's going to get the same the full net present value accorded based on the definition of the measure and and the life.

2:29:50  
So the fact that it's low in the first years and high in the later years won't won't be lost, right.

2:29:57  
But then if you look at just the single year near near term year value as the cost, the avoided cost this year, like what?

2:30:07  
What cost does it avoid this year or next year or the following year according to your methodology, I imagine you would say that's an accurate statement, but looking at the value of that misses the value of the asset to the long term energy system in the state.

2:30:21  
Would you agree with that?

2:30:22  
No, that value is captured in the subsequent in the net present value analysis.

2:30:27  
So it's not missed at all, but you so would you need to use a levelized value over the life of the asset And no, in fact, levelizing introduces some imbalance of the costs and the and the benefits of doing a nominal.

2:30:46  
As long as we're consistent on using nominal annual values, then you know the economic results of an MPV calculation come out the same.

2:31:03  
OK, I have to look at this further.

2:31:10  
OK, let's go to the chat.

2:31:12  
We have a question from Andrea White, PCF.

2:31:15  
Why does the ATC only use the DTIM and not the local net benefit analysis method to calculate SDG needs avoided transmission cost.

2:31:25  
Do SDG and E and SCE decide whether the DTM or the LNBA methods are used?

2:31:35  
I would say yes, largely that decision is, is left to the utilities.

2:31:40  
We provide some guidance on kind of the general method each year when we when we request the data from them.

2:31:46  
And these are the methods that kind of have consistently been used by each of these two utilities.

2:31:53  
But it's not, it's not a decision that we're making in the course of each update cycle so much as I'm requesting that input from the utilities.

2:32:13  
OK, we have another hand raised from Tom.

2:32:15  
Go ahead.

2:32:19  
Yeah, Thanks Tom Beach with Sia.

2:32:21  
I, I just wanted to provide a little more light on Eric Borden's question.

2:32:29  
So the, the set of data that should be used for avoided transmission is actually a litigated issue in this case that has not been decided by the Commission.

2:32:41  
There's a record on it.

2:32:43  
It wasn't addressed for some reason in the proposed decision.

2:32:47  
We certainly are asking the Commission to address it in in the final decision.

2:32:53  
So you know, there was a record developed in this case on the set of avoided of transmission costs that should be used to update the ACC in in this cycle.

2:33:09  
And so that that may get decided in in the final decision and that there is a record that is beyond just what the utilities have told staff in E3 and data responses.

2:33:29  
Sorry, just just in case, was there was there a question there?

2:33:34  
Do you have any or was just a comment that that's just a comment.

2:33:38  
I just wanted to Eric ask, you know, where the data came from and you said it came from the utilities.

2:33:44  
And I just wanted to clarify that, that that's actually subject to litigation in the case.

2:33:50  
OK, appreciate the context.

2:33:52  
Thanks.

2:33:54  
Were there any other questions remaining?

2:33:57  
I think I see a hand raised from Brad.

2:34:04  
Is that still from the earlier question?

2:34:06  
Yeah, I'm not sure.

2:34:07  
Here, I can go ahead and unmute.

2:34:09  
Brad, do you have an additional question?

2:34:11  
No, I'll take my hand down.

2:34:13  
OK, great.

2:34:19  
All right.

2:34:20  
Looks like there's no further hand raised and no further questions in the chat, so we can move on to the that'll cost test results.

2:34:30  
Great, we're almost there.

2:34:32  
Thank you all for still hanging out here with us.

2:34:36  
This is the last section with and it is also a new addition to the ACC in 2024.

2:34:44  
So starting in this cycle, both the electric and gas models will include a societal cost test perspective and the user will be able to toggle between the TRC and the ICT, right.

2:34:59  
Let's go to the next slide.

2:35:01  
I want to give a bit more context was the difference between the TRC and ICT.

2:35:07  
So the ACC we had been using WORM updating until this cycle was mainly from a total resource cost or TRC perspective.

2:35:20  
This represent kind of the avoiding cost from California's state perspective, well like societal cost tag or ICT perspective.

2:35:29  
On the other hand really represent a kind of a broader broad societal perspective from a for avoided costs.

2:35:38  
As I'm showing on the right the screenshot, if you go to the electric model right now, you will be able to toggle between the TRC and ICT options and it will automatically produces different results.

2:35:54  
In terms of the differences, the table at the bottom listed the major differences between TRC and ICT starting with the GHG of what it costs.

2:36:04  
The TRC uses the carbon trade allowance prices as the price for well the ICT use uses the social cost of carbon that's coming out of the Inter agency working group of social cost of carbon.

2:36:20  
And then we also applied a base social of carbon and a high case of social, social cost of carbon for the SCT perspective.

2:36:29  
And then in terms of discount rate, the TRC uses 7.3, the IOU, WAC, well, the SCT uses a cycle discount rate that's 3%.

2:36:40  
And then compared to TRC, the ICT also includes an air quality adder.

2:36:46  
This represents the health impacts of gas combustion in the electric system.

2:36:52  
And then finally compared to TRCSCT assumes a higher methane leakage rates and this captures the out of state upstream nothing leakage.

2:37:02  
Well, the TRC, the .6% captures the in state nothing leakage rates.

2:37:08  
All right.

2:37:11  
When you come to the next slide, want to use one slide to show the difference, one difference between TRC and ICT that is the GG awarded cost and the capacity awarded cost.

2:37:27  
The first is that in the integrity calculation, as I was saying, the GHT avoid floor for ICT is set by the social cost of carbon as well as the air quality adders rather than carbon trade.

2:37:40  
So that's that is what's driving the higher GHT avoided cost in the near term.

2:37:47  
If you look at the chart at the bottom left, you'll see that the ICTGG will cost in this case also include air.

2:37:57  
They also include air quality adders represent in dark brown and yellow are higher than the TRC in the near term.

2:38:06  
ICT also has a lower discount rate which makes the missing money for solar in their integrated calculation more pronounced or less discounted.

2:38:17  
And that's the main driver for the high GG.

2:38:20  
What it cost for ICT in later years?

2:38:25  
And if you compare the GG word it cost between the two cases, the base case and the high case, the GG word it cost for the base case are higher than the floor which is not showing here.

2:38:38  
But if you imagine the the word it cost by 2029 cannot just go as a straight line.

2:38:47  
That will be the floor for the GG word it cost and then for the high case, the GG word it GHG woody cost cost, air quality adders follow very closely to the floor.

2:39:01  
And then looking at the capacity woody cost, because the GHG woody cost are higher in the ICT version.

2:39:08  
And because of this interdependence between GHG and the capacity woody cost, we see that for ICT cases, the capacity woody cost lower compared to TRC.

2:39:22  
And then between the base and high, the capacity body cost is lower for the high compared to the base.

2:39:28  
All right, let's go on to the next slide.

2:39:35  
This is a similar chart that I showed earlier, which is the 20 year level as values that started in 2024 to and then go on until 2044.

2:39:48  
We see that compared to TRC at CT has higher GHG adders and lower generation capacity value.

2:39:57  
So the that's the GHG is the light.

2:40:01  
Blue part and the capacity is the yellow part and overall the ICT has higher of what it cost and that's mainly because of the higher nothing leakage rates and the addition of air quality adders, right.

2:40:21  
I think we have two more slides before any questions.

2:40:27  
This is a similar slide of showing the as comparing the TRC versus SCT avoided cost of a few example Ders where I kind of mix and matching here.

2:40:40  
So I labeled depending on the Ders we're talking about either represent the avoided cost or the cost or depending on whether the DER is load reducing or increasing.

2:40:52  
So overall we see that with the higher GHG of what it cost and the thin leakage and air qualities, most Ders see a higher like the load reducing DERC higher avoided cost, while the load increase in DERC higher costs.

2:41:14  
And we see also see a similar trade off between the GHG avoided cost and capacity avoided costs.

2:41:22  
So higher chichi avoid costs will lower capacity avoid costs.

2:41:28  
And this is for the ICT high case.

2:41:32  
And next slide, we'll quickly show the results for the ICT based case.

2:41:39  
I know, I swear those are two different slides but the story is the same between the TRC and ICT case and I believe that is the last slide for the ICT session.

2:41:55  
Happy to answer any questions.

2:42:00  
Looks like we have a couple of hands raised.

2:42:02  
We can start with Gene.

2:42:04  
You should be able to unmute yourself.

2:42:11  
Yes, this is Gene Armstrong Garcia and I raised my hand during this session because it was the last one.

2:42:16  
But this is more of A and I didn't want the bookshop to end without without asking it.

2:42:22  
This is a process question.

2:42:24  
So it's really to energy division and, and the, and the procedures that the Commission put in place in 2022.

2:42:30  
In their 2022 ACC order, they said that after staff, you know, held this workshop that would, it would provide an opportunity for stakeholders to ask data request and then, you know, for staff or E3 to respond and, and then submit informal comments.

2:42:51  
And I noted in the e-mail that was sent out, there is a date set for informal comments, but there was no date set for data requests for when they should be, you know, put in and when they would be responded to.

2:43:04  
So that's one question.

2:43:06  
And if that is going to be allowed.

2:43:09  
And if so, I'm concerned that the August 6th date for informal comments might be coming up a little too quickly.

2:43:17  
So could could somebody from energy division respond to that?

2:43:24  
Hi Gene, thanks for the question.

2:43:25  
This is Dan Busch.

2:43:26  
I'm appropriate and energy division.

2:43:30  
I appreciate the, the first question and I did notice this morning the, the thing that you're talking about, we're going to need to huddle briefly and we will try and send out communication very quickly in terms of any opportunity for, for data requests On the second, unfortunately there is really not much time for us to, to extend.

2:43:53  
I understand the, the, the, the issues at play here.

2:43:57  
We'll try to move quickly to respond.

2:43:58  
I, I, I just want to warn folks that I don't think we have much leeway to, to relax any of the deadlines given where we are and where we need to get to.

2:44:07  
But again, I'm not making any final determinations.

2:44:10  
I appreciate the question.

2:44:11  
We'll try to respond quickly.

2:44:13  
I I'd appreciate that, but I'd also point out that the, you know, the Commission isn't even voting on this decision until August 1st.

2:44:21  
There could be changes.

2:44:22  
I mean, people submitted comments asking for various changes, pointing out certain errors.

2:44:27  
So this all seems to be happening a little too fast.

2:44:33  
I understand the deadline.

2:44:34  
I'm very aware of it.

2:44:35  
See, it does want the final ACC voted out, I mean, and, and ready to go the resolution by the end of the year.

2:44:42  
But we also know that certain processes were put in place.

2:44:46  
We advocated very strongly for the processes Commission listened to us and we do not want them ignored.

2:44:52  
So I'd, I'd ask you to not only give us consideration for the data request, but enough time to get them in, get them responded to and do something you know worthwhile with them to have an opportunity to analyze them and use them in our comments.

2:45:08  
Thank you.

2:45:09  
I hear you very clearly, Jean.

2:45:11  
Thank you noted and and we will respond as quickly as we can.

2:45:15  
Your concerns are, are, are are very noted and you articulated them well and will respond.

2:45:27  
OK, let's go to the next on the phones.

2:45:32  
Holly should be able to unmute yourself.

2:45:40  
Thanks.

2:45:40  
This is Hallie Fitzpatrick and I'm a consultant here for a so-called gas and there was quite a bit of discussion about some nuances in the electric model, but but not I didn't, I didn't catch too much detail on the gas model.

2:45:59  
We did notice that there were some upgrades so to speak, in the model.

2:46:04  
I'm wondering is there going to be a, a showcase of of of of that model at any time?

2:46:22  
This is Fon Singh, I can respond.

2:46:24  
I apologize.

2:46:25  
We have one slide that dedicated to the gas model earlier in this presentation.

2:46:31  
The reason we didn't talk much about it was mainly because there's no methodology change for the gas model and all the changes are based on the because of data updates.

2:46:44  
Is there anything you're particularly?

2:46:50  
Yeah, I, I, yeah, I have two pay attention, want, want, want us attention to.

2:46:54  
Yeah, a couple.

2:46:55  
One is a question and it's about societal.

2:46:59  
And I don't know if this is a deliberate and purposeful and correct outcome or or a mistake.

2:47:05  
But if you choose societal cost test in the gas model and you choose a utility and you choose a customer class, the values stay the same.

2:47:17  
The, the, the, the, the total of the levelized values and other values are the same no matter if you what end use you choose or what emissions control you choose.

2:47:29  
And so those, those seem to be irrelevant in SCT and I'm wondering if you could speak to that.

2:47:35  
And then I likely have one more, one more guess model question after that.

2:47:41  
Sure.

2:47:41  
Yes, I can speak to that.

2:47:44  
The key difference between the TRC and ICT in a gas model is what would be that with SCT we would use societal discount, societal discount rate of 3% to escalate that interim GHG cost of carbon rather than the what we currently use which is like 7.3%.

2:48:11  
The utility work.

2:48:13  
The problem was with that 3% escalation, the SCT actually resulting in lower GHC cost of carbon, lower cost of carbon compared to TRC.

2:48:24  
So we decided to omit that that difference between TRC and SCT.

2:48:32  
So that is my understanding as the current, I guess the current state between ICT and TRC, but I more certainly go back to the team like to, to the PD and really look through the key difference and see if we made any, any errors on the model.

2:48:56  
Yeah, did did you just say that when you use the utility WAC, the results weren't what you expected or the like?

2:49:14  
I just I don't know the right way to phrase it, but are we putting our thumb on the scale to get a certain result that we want here or with this one?

2:49:21  
I I don't I couldn't really follow what what you were saying there with choose choosing a discount rate.

2:49:27  
Sure.

2:49:27  
Yeah, it it is a nuance.

2:49:29  
So let me maybe describe how we are currently calculating the cost of carbon in the gas model.

2:49:37  
There are two steps.

2:49:38  
First we select, we, we use, we decide the first value to use in 2024.

2:49:47  
And this value is basically the carbon abatement cost of residential electrification and it is the same across ICT and TRC and I think about $114.00 per ton I think in 2024 or 2022.

2:50:04  
And then we escalate this value for TRC using the three using 7.3 percent, which is the utility WAC.

2:50:19  
Now if we were to apply the change using SCT methodology, we would escalate this value using the 3%, 3% rate.

2:50:36  
But with that 3%, we actually have lower cost of carbon for SCT.

2:50:42  
So that's why we decided to not include that in our model.

2:50:47  
And that is my.

2:50:48  
But I guess my question is that why did you decide to the results are what they are like why did you decide to change it?

2:50:57  
I see.

2:50:59  
I think we all we expect that with this ICT perspective, the cost of carbon should be higher compared to TRC because the key difference between TRC and SCT is SCT includes a kind of coming from a broader societal perspective, while TRC only represents the perspective of California as a state.

2:51:25  
OK, well, I won't take any more time on this.

2:51:26  
Thanks.

2:51:27  
I'll, I'll look into it.

2:51:28  
I might, we might follow up separately.

2:51:31  
So thank you for that and we this one is just since I have the mic I, I I think you might want to check.

2:51:41  
I didn't discover this error, but someone else did that the emissions factor are set to the start year in 2022 and it always pulls from 2020.

2:51:54  
So I, I think, I think one of the emissions look UPS or index functions, it is, is not, is not working properly.

2:52:01  
And we can, we can follow up later on that, that that might be something good to resolve before the draft resolution for sure.

2:52:09  
Yeah, I appreciate that, that definitely that's yeah, we'll we'll look into that as well.

2:52:14  
You said that's in the gas model, right?

2:52:28  
OK, let's keep going.

2:52:33  
Jean, did you have another comment, or is your hand raised from earlier?

2:52:38  
I'm sorry, I forgot to put my hand down.

2:52:41  
I will do it.

2:52:41  
Yeah.

2:52:41  
Great.

2:52:42  
All right, let's go to Ted Howard then.

2:52:47  
I believe you were next.

2:52:53  
You should be able to unmute yourself and small business utility advocates.

2:53:04  
Yeah.

2:53:04  
Just curious regarding the discount rate utilized, given that the EPA has looked this over and recently reduced the discount rate they applied from 3% to 2% and they go into great reasoning and base it on some pretty good analysis it looks like.

2:53:25  
Just curious what your thoughts were on that.

2:53:27  
Have you considered the 2% discount rate?

2:53:29  
I know New York has also been using a 2% social cost of carbon discount rate.

2:53:36  
What are your thoughts there and how you chose 3%?

2:53:50  
I think the 3% was a decision was an input set by the proposed decision and that was what B3 used in the model.

2:54:05  
Yeah.

2:54:06  
So and as E3 did what we were given from the PDI, see, OK.

2:54:13  
So it wasn't like you really had a choice in the matter.

2:54:15  
You went with what the PD required.

2:54:18  
So that was kind of ended any further analysis from there?

2:54:22  
Yeah, that's right.

2:54:23  
Yeah, not much you can do there.

2:54:25  
OK, well, we'll see how that evolves because I think a lot of science is kind of pushing towards climate change accelerating.

2:54:32  
And if so, you know, a a lower discount rate might be appropriate.

2:54:36  
But again, this isn't the venue for discussing that further.

2:54:40  
So I'll I'll add that in comments.

2:54:41  
Thanks.

2:54:42  
Yeah, if yeah, I think that will be a great venue to provide new information.

2:54:47  
OK, OK, great.

2:54:50  
Let's go to Sam.

2:54:53  
You should be able to yourself.

2:54:58  
I don't know, taking time at the very end here, but I was quite confused by the comment just made about the in response to a question a couple questions ago about the discount rate resulting in a lower value and referring it to an escalation rate.

2:55:16  
An escalation rate is is absolutely not the same thing as a discount rate.

2:55:21  
And if you're using a lower discount rate, that should give you a higher value in the future because you're not discounting it as much.

2:55:31  
So could you kindly explain that?

2:55:34  
Thank you.

2:55:36  
Yeah, thank you.

2:55:37  
That is a great comment.

2:55:43  
We agree that escalation rates are not the same as discount rate, but that was what was used and adopted to be used in the gas model.

2:55:59  
And I think the, we recognize that this methodology is an interim approach as we try to figure out the, the true value of the, the, the carbon of the cost of carbon for gas, especially in the face of adopting electrification.

2:56:24  
So that is a excellent comment.

2:56:30  
Yes, cuz whatever value you start with the, the, you would have one level for that value escalating over time.

2:56:40  
And then separately you would look at the, the rate at which you are discounting that over time.

2:56:47  
And the social cost test will always give you a, a higher future value because it doesn't discount it as much.

2:56:57  
Thank you.

2:57:03  
OK, so we are at time.

2:57:05  
So I just want to be conscious of everyone's time because we've been, you know, here since 1:00 PM.

2:57:10  
So I think that if there are additional questions or comments at this time, if you could submit them as part of the informal feedback due on August 6th.

2:57:18  
I think Alex, if you want to provide the close out here, please feel free.

2:57:26  
Certainly, Margo, I thank you all for being here and you know, taking the time to go through us as we've walked through this whole workshop and you know, appreciate all the comments and questions.

2:57:36  
Of course.

2:57:37  
Now as stated here, informal comments in the draft ACC calculator or do you via e-mail?

2:57:42  
I close the business on August 6th, 2024, two weeks from now.

2:57:46  
In particular, as was noted in the 2022 ACC decision on timeline for this and for informal comments, do send them to me at my e-mail address, Emily Postering at emily.postering@cpcthatsca.gov and the R 2211013 services as well.

2:58:04  
So we'll make sure to encapsulate all of that and capture all of the comments that were both set or you didn't get the chance to save for today's or today's workshop.

2:58:16  
And I believe that is about it, unless does anyone else has something we need to cover?

2:58:31  
All right, I am not hearing anything.

2:58:33  
So I think that about concludes the workshop on the 2024 ACC draft calculator.

2:58:40  
Thank you all for being here.